# APPENDIX 5

Transend, *Renewal capital expenditure, a response to the draft decision*, January 2009

# Renewal Capital Expenditure

# A response to the draft decision

**APPROVED**

TRANSEND

## CONTACT

*This document is the responsibility of the Asset Strategy & Planning Group, Transend Networks Pty Ltd, ABN 57 082 586 892.*

*Please contact Transend's Manager Asset Strategy & Planning Group with any queries or suggestions.*

## REVIEW DATE

*This document is due for review - Not Applicable.*

## RESPONSIBILITIES

### Implementation

*All Transend staff and contractors.*

### Audit

*Periodic audits to establish conformance with this document will be conducted by Transend's Asset Strategy & Planning Group.*

### Compliance

*All Group Managers*

### Document Management

*Asset Strategy & Planning Group*
*Revenue Reset Project*

## MINIMUM REQUIREMENTS

*The requirements set out in Transend's documents are minimum requirements that must be complied with by Transend staff and contractors, including designers and other consultants. The user is expected to implement any practices which may not be stated but which can reasonably be regarded as good practices relevant to the objective of this document without non-compliance with the specific requirement of this document. Transend expects the users to improve upon these minimum requirements where possible and to integrate these improvements into their procedures and quality assurance plans.*

 

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# EXECUTIVE SUMMARY

This document responds to the Australian Energy Regulator's (AER's) draft decision for the forthcoming (2009–14) regulatory control period. Transend's revised revenue proposal seeks reinstatement of renewal capital expenditure deferred by the AER in its draft decision. This document supports Transend's revised revenue proposal by providing further justification with respect to renewal capital expenditure for the:

- 110 kV substation redevelopment projects associated with the replacement of Reyrolle type OS10 110 kV (Reyrolle 110 kV) circuit breakers;
- Farrell and New Norfolk substations secondary system replacements projects; and
- Burnie–Waratah 110 kV transmission line wood pole replacement project.

In terms of Transend's forecast renewal capital expenditure the proposed reduction is approximately a quarter of that expenditure category. In effect, a reduction of this magnitude would eliminate practically all of Transend's proposed increase in renewal capital expenditure for the forthcoming regulatory control period. Transend is of the view that this would have a significant impact on the performance of the transmission system, and, in turn customers, over the medium to long term. Given the materiality of the proposed reduction in renewal capital expenditure, Transend has revisited the matters raised in the draft decision in relation to the renewal projects where the AER has concluded that reductions are warranted.

The AER reached broadly positive conclusions in respect of Transend's 2009–14 capital expenditure forecasts. These conclusions followed a detailed project-based review by the AER's consultants, Worley Parsons and Nuttall Consulting, in addition to an examination of Transend's governance and investment decision-making processes.

A detailed project-based assessment of Transend's asset renewal projects by Nuttall Consulting led the AER to conclude that particular asset renewal projects should be deferred until the next regulatory control period (2014–19). Transend has conducted its own internal review of forecast renewal capital expenditure after carefully considering the comments made by the AER and its consultants. This document provides information in support of Transend's revised revenue proposal renewal capital expenditure forecast.

The document comprises three sections, providing further information of the renewal strategies and projects. The remainder of this document is structured as follows:

- Section A sets out Transend's response to the matters raised in the draft decision regarding 110 kV substation redevelopment projects associated with the replacement of Reyrolle 110 kV circuit breakers;
- Section B sets out Transend's response to the matters raised in the draft decision regarding the Farrell and New Norfolk substations secondary system replacements projects; and
- Section C sets out Transend's response to the matters raised in the draft decision regarding the Burnie–Waratah 110 kV transmission line wood pole replacement project.

Given the significance of the 110 kV substation redevelopment projects associated with replacement of Reyrolle 110 kV circuit breakers, Section A also includes an overview of both the 110 kV circuit breaker replacement program and the key investment drivers for the 110 kV substation redevelopments.

Additional supporting information for each category of expenditure is included as attachments to this document.

# 1 SECTION A: 110 KV SUBSTATION REDEVELOPMENT PROJECTS

## 1.1 BACKGROUND

In relation to the 110 kV substation redevelopment projects associated with replacement of Reyrolle OS10 circuit breakers, the AER's draft decision concurred with Nuttall Consulting's opinion that the proposed replacement program is overly aggressive. In reaching this conclusion, the draft decision noted two findings in the Nuttall Consulting report[1]:

(a) the proposed replacement program would result in the average age of Transend's 110 kV breaker population being one of the youngest of its peers[2]; and

(b) Transend's economic evaluation was relatively high level and did not consider the priority of the breaker replacements in terms of the poorest or better performing fleet cohorts and the criticality of the substations.

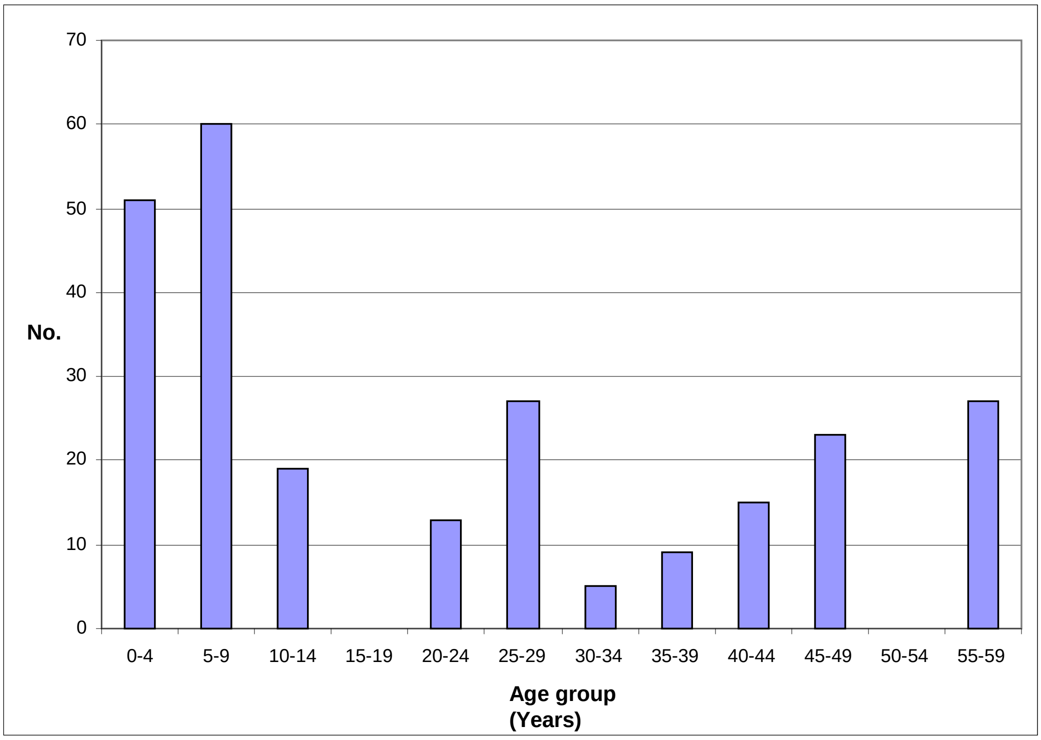
In response to the first point, Transend notes that Nuttall Consulting correctly recognised that the Reyrolle OS10 circuit breakers are 'very old'[3], the oldest currently being 58 years. Given the age of these circuit breakers, and the age profile of the circuit breaker fleet, their replacement will result in a significant reduction in the average age (especially if the average age of the remaining population is relatively young). However, the extent of the reduction in the average age does not of itself indicate that the replacement program is overly aggressive. Renewal profiles will to a large extent be a function of transmission system development over time. Figure 1 presents the current age profile of Transend's 110 kV circuit breakers. Figure 1 indicates that, if the circuit breakers older than 45 years are replaced, the average age of the circuit breaker population would reduce significantly.

[1] Nuttall Consulting, Review of Transend Revenue Proposal Asset Renewal Capital Expenditure, November 2008, pages 35 and 38.

[2] It is noted that the comparison uses inconsistent time periods by comparing Transend's age profile in 2013–14 with the existing age profile for Transend's peers.

[3] *Ibid*, page 39.

**Figure 1 – Age profile of 110 kV circuit breakers as at 2008**




In concluding that Transend's replacement program is 'overly aggressive', Nuttall Consulting appears to place weight on the mistaken belief that Transend is compressing a 10–year Reyrolle 110 kV circuit breaker replacement program into a shorter period.

However, this is an ongoing program, which will extend into the 2014–19 regulatory control period. Nuttall Consulting's analysis also appears to place inappropriate weight on the importance of average asset age. While asset age may indicate a need to replace or renew assets, Transend's asset renewal programs are not predominantly age-based.

Transend considers issues associated with asset condition; asset performance; spares availability and product support; technical obsolescence; physical security; technical, safety and environmental compliance; and operational support systems; as well as age, when developing its replacement strategies. Transend continues to implement an ongoing program that prioritises asset replacements in a prudent and efficient manner.

In response to the second point, Transend accepts that the original economic analysis that underpinned the proposed replacement of the Reyrolle 110 kV circuit breakers did not consider partial deferral or gradual replacement over an extended period. To address this shortcoming in the original analysis, Transend has subsequently undertaken additional work to provide a more comprehensive assessment of deferral options.

Transend's analysis considers optimal scoping and timing for the replacement of all circuit elements for bays that contain the Reyrolle OS10 circuit breakers. This analysis confirms the appropriateness of the original planned replacement program. Rather than being 'aggressive', the program has delayed replacement of this plant well beyond timing adopted by its peers.

Transend's replacement strategy is supported by information from other Australian and New Zealand transmission companies, who have completed their replacement programs for Reyrolle circuit breakers some years ago, responding to identical drivers to those experienced by Transend. Transend has reviewed its original proposal for the 110 kV substation redevelopment projects associated with the replacement of Reyrolle 110 kV circuit breakers and maintains its view that this forecast is reasonable. Section A provides further information to support this view. Noting that the

AER's consultant – Nuttall Consulting – has included analysis of fleet age profiles in reaching its conclusions, further information is included regarding the age profile of the circuit breakers and other related plant in need of replacement.

## 1.2 TRANSEND REVENUE PROPOSAL AND NUTTALL CONSULTING REVIEW

Transend's revenue proposal for the forthcoming regulatory control period included the commencement of 13 110 kV substation redevelopment projects, of which seven will be completed in the forthcoming regulatory control period. Nuttall Consulting, in its review of the asset renewal projects that were included in Transend's revenue proposal, selected nine of the 13 110 kV substation redevelopment projects to review in detail. Of these projects, six contained Reyrolle 110 kV circuit breaker replacements. A project to redevelop the entire Arthurs Lake Substation that contains one Reyrolle 110 kV circuit breaker was also selected for review.

Nuttall Consulting identified linkages between the 110 kV substation redevelopment program and the Sprecher & Schuh and Reyrolle 110 kV circuit breaker replacement programs and considered that the planned circuit breaker replacements could be the trigger for much larger substation redevelopment projects.

Nuttall Consulting concluded that only 60 per cent of the 110 kV substation redevelopment projects associated with the Reyrolle circuit breaker program would be required in the forthcoming regulatory control period. The substation redevelopment projects reviewed by Nuttall Consulting that include the replacement of Reyrolle 110 kV circuit breakers are presented in Table 1.

**Table 1 – Replacement Reyrolle 110 kV circuit breakers**

| Project identification | Project description | Estimated cost ($m 2008–09) | Commissioning year |
|---|---|---|---|
| ND0910 | Arthurs Lake Substation redevelopment | 4.1 | 2014[1] |
| ND0908 | Burnie Substation 110 kV redevelopment | 8.1 | 2014 |
| ND0733 | Creek Road Substation 110 kV redevelopment | 33.1 | 2014 |
| ND0968 | Knights Road Substation 110 kV redevelopment | 6.6 | 2015[1] |
| ND0949 | Meadowbank Substation 110 kV redevelopment | 4.6 | 2015[1] |
| ND0953 | Palmerston Substation 110 kV redevelopment | 13.7 | 2014 |
| ND0709 | Tungatinah Substation 110 kV redevelopment | 19.5 | 2015[1] |

Note 1: Commissioning dates of 2013 for project ND0910 and 2014 for ND0968, ND0949 and ND0709 were incorrectly identified for these projects on page 105 of Nuttall Consulting's report

The only other projects in Transend's revenue proposal that included the replacement of Reyrolle 110 kV circuit breakers are the Rosebery Substation HV redevelopment project (one unit) and Temco Substation 110 kV redevelopment (three units). These projects are planned to be commissioned in 2015 and 2016 respectively and were not selected for review by Nuttall Consulting. It is noted that the AER has also removed 50 per cent of the funding for the Temco Substation 110 kV redevelopment project. Transend considers that the capital expenditure for this project should be reinstated for the reasons outlined in this document.

## 1.3 REVISED REVENUE PROPOSAL

The purpose of this section is to provide further information about the 110 kV substation redevelopment projects that include the replacement of Reyrolle 110 kV circuit breakers. These projects are included in Transend's revised revenue proposal.

As a point of clarification, Transend does not agree with the Nuttall Consulting assertion that the planned circuit breaker replacements trigger much larger substation redevelopment projects. Transend has considered the condition of all 110 kV assets at the respective substations, including power transformers, instrument transformers, disconnectors, post insulators and protection and control equipment. After taking into account the condition issues presented by each of the asset categories at the substations selected for review, Transend considers it prudent and efficient to redevelop the substation rather than undertake targeted asset replacements. This approach is considered on a case-by-case basis and Transend does not adopt this approach in all circumstances.

Transend has undertaken further analysis and has prepared additional information to support the 110 kV substation redevelopment projects associated with the Reyrolle 110 kV circuit breaker replacement program. Specifically, Transend has prepared the following additional information to support the revised revenue proposal.

### 1.3.1 Risk review and transmission circuit criticality

An objective assessment of the risks presented by each of the assets included in the 110 kV substation redevelopment projects has been undertaken. This review considers asset condition, consequence of failure (safety, environment, failure consequence costs, and operational consequences) and transmission circuit criticality.

The criticality of each transmission circuit has been assigned with consideration of the following factors: National Electricity Market Management Company (NEMMCO) oversight, forecast maximum demand and customer impact.

The methodology used to determine the risk is consistent with risk assessment models used both locally and internationally among electricity utilities.

### 1.3.2 Impact on reliability of electricity supply

Transend has analysed the impact that the loss of each transmission circuit would have on the reliability and security of the transmission network. This information, together with an accurate determination of the probability of failure, has been used to determine a probability weighted impact of the loss of electricity supply. This information has been used in the revised economic analysis for each 110 kV substation redevelopment project.

### 1.3.3 Project justification

Transend has reviewed the economic analysis and investment evaluation summaries for each of the projects reviewed by Nuttall Consulting and has provided additional information. A summary of the justification for each project under consideration is attached to this report.

Transend considers, and Nuttall Consulting agrees, that economic analysis is only one component of the renewal investment decision. Other good electricity industry practice factors, including safety, environment, physical security, technical compliance, technical obsolescence, prudent works planning, customer considerations, outage management safety considerations, also form part of the project justification.

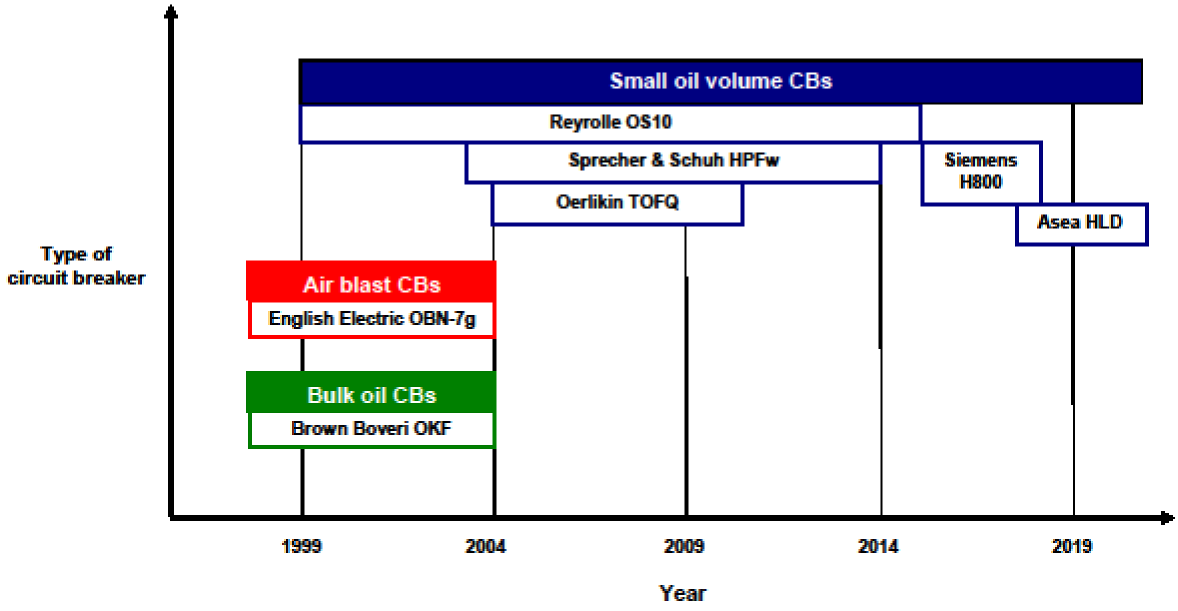
## 1.4 110 kV Circuit Breaker Replacement Program Overview

In relation to 110 kV substation redevelopment projects associated with the replacement of Reyrolle 110 kV circuit breakers, the AER's draft decision concurred with Nuttall Consulting's view that the proposed replacement program is overly aggressive. This section provides further information about the 110 kV circuit breaker replacement program and demonstrates that the replacement program is not overly aggressive.

The 110 kV circuit breaker replacement program commenced in 1998 and has been developed and prioritised with consideration of a range of performance issues presented by the 110 kV circuit breaker population. Figure 2 presents an overview of the circuit breaker makes and types that are part of the replacement program and the timing of their replacements.

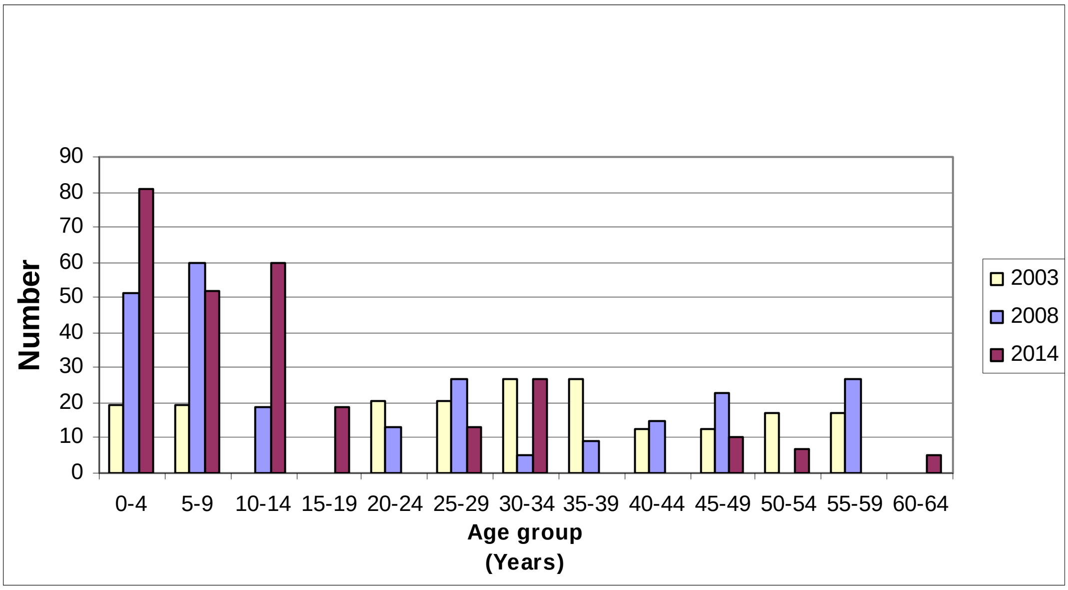
Figure 2 clearly shows that the 110 kV circuit breaker replacement program is a long term program that needs to continue to at least 2020.

**Figure 2 – 110 kV circuit breaker replacement program overview**




The age profiles of the circuit breaker population at 2003 and 2009 and projected in 2014 (including anticipated asset additions from augmentation projects) are presented in Figure 3. The figure shows that even though the average circuit breaker age is decreasing, in 2014 there will still be 22 circuit breakers that will have exceeded their nominal service life of 45 years. Although age is not the sole driver for asset replacement, it is our experience that aged circuit breakers that are of obsolete technology are more susceptible to reliability and performance issues. They also require more intensive monitoring and maintenance which has an adverse impact on operating costs.

**Figure 3 – 110 kV circuit breaker age profiles at 2003, 2008 and forecast in 2014**



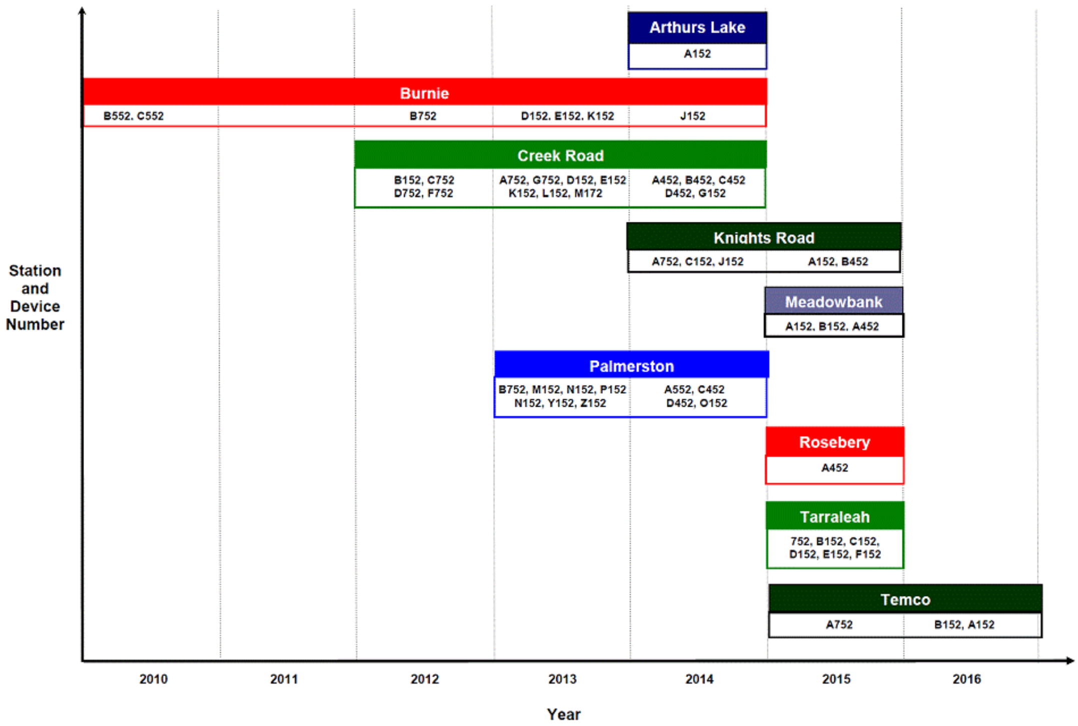

The timing of the Reyrolle 110 kV circuit breaker replacements has been determined taking into account a number of key factors including asset condition, transmission circuit criticality and the performance and condition of assets associated with the circuit breakers. The asset replacements also need to be co-ordinated and prioritised with consideration of the overall works program. Figure 4 presents an overview of the Reyrolle 110 kV circuit breaker replacements and shows that this component of the 110 kV circuit breaker replacement program will extend well into the 2014–2019 regulatory control period.

Nuttall Consulting has made the assumption that Transend is not complying with its own Circuit Breaker Asset Management Plan in that Transend proposes to replace all of its Reyrolle circuit breakers in the forthcoming regulatory control period rather than over a 10 year period. Figure 4 clearly highlights that the replacement program for Reyrolle 110 kV circuit breakers will extend over at least an eight year period out to 2016 (note that the diagram does not show the two circuit breakers that were replaced at Chapel Street Substation in 1999 or the two units replaced at Kermandie Substation in 2005). The overall replacement program for Reyrolle circuit breakers commenced in 1999. This represents a 17 year replacement program for Reyrolle circuit breakers. It is also important to note that the replacement of Reyrolle 110 kV circuit breakers is only one investment driver for the 110 kV substation redevelopment projects.

As noted in Transend's revised revenue proposal[4], Transend's replacement strategy is supported by information from other Australian and New Zealand TNSPs, which completed replacement of all Reyrolle OS10 circuit breakers some years ago, responding to similar drivers to those experienced by Transend.

[4] Transend's Revised Revenue Proposal, page 39

**Figure 4 – Overview of the Reyrolle 110 kV circuit breaker replacements**




## 1.5 110 kV SUBSTATION REDEVELOPMENTS OVERVIEW

This section provides an overview of the 110 kV substation redevelopment projects that include the replacement of Reyrolle 110 kV circuit breakers. Table 2 presents an overview of the key assets that form the scope of each 110 kV substation redevelopment project. Although each of the projects is titled 'substation redevelopment' the extent of redevelopment varies on a case-by-case basis. For example the Burnie, Knights Road, Meadowbank and Palmerston substation redevelopment projects do not include the wholesale replacement of all 110 kV assets. Assets that have already been replaced or are considered to be in a serviceable condition will be retained in service where it is practicable and cost-effective to do so.

The Arthurs Lake, Creek Road and Tungatinah substation redevelopment projects are full substation redevelopments because the vast majority of the assets are in a condition where wholesale replacement is required and it has been demonstrated that it is more cost-effective to undertake wholesale replacements rather than piecemeal targeted replacements. There is also a significant opportunity to realise considerable whole-of-life cost benefits (particularly with the Creek Road and Tungatinah substation redevelopment projects) by reconfiguring and rationalising the number of assets at the substations.

The scope for each 110 kV substation redevelopment project has been developed taking into account a broad range of factors including the condition of all assets at the substation, future transmission network development needs and the optimal timing in the context of the total capital works program and access to the transmission network to carry out the required works.

Further details of the drivers for the asset replacements for each project are provided in the asset management plan relevant to the particular category and the investment evaluation summary for each project.

**Table 2 – Key asset replacements that comprise the 110 kV substation redevelopment projects**

| Project description | Supply transformers (units) | Circuit breakers (units) | Current transformers (units) | Voltage transformers (units) | Disconnectors (units) | Post insulators (units) | 110 kV Protection schemes (bays) |
|---|---|---|---|---|---|---|---|
| Arthurs Lake Substation redevelopment | 1 | 1 | 3 | - | - | 6 | 1 |
| Burnie Substation 110 kV redevelopment | - | 8 [1] | 33 | - | - | - | 3 |
| Creek Road Substation 110 kV redevelopment | - | 16 | 60 | 21 | 29 | 309 | 6 |
| Knights Road Substation 110 kV redevelopment | - | 5 | 15 | 6 | 3 | 94 | 4 |
| Meadowbank Substation 110 kV redevelopment | - | 3 | 9 | 5 | - | 45 | 2 |
| Palmerston Substation 110 kV redevelopment | - | 11 | 33 | 11 | - | 225 | 4 |
| Tungatinah Substation 110 kV redevelopment | - | 15 [2] | 21 | 18 | 30 | 396 | 10 |

Note 1: Three of the 110 kV circuit breakers at Burnie Substation are Sprecher & Schuh units. The need to replace these units has been accepted by the AER.

Note 2: Nine of the circuit breakers from Tungatinah Substation 110 kV redevelopment will be re-deployed elsewhere in the transmission network.

### 1.5.1 Transmission circuit criticality

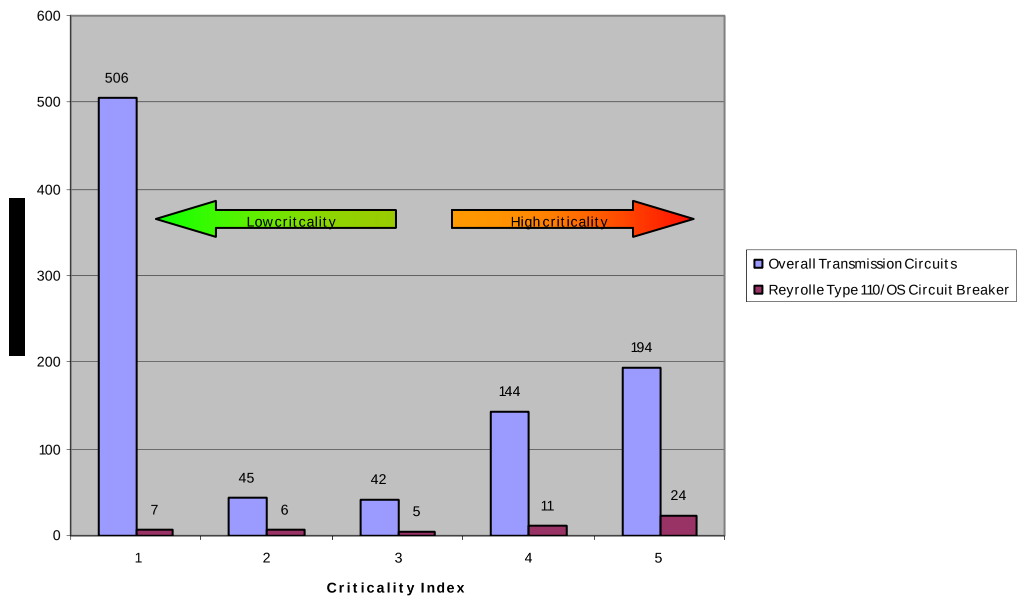
The criticality of each transmission circuit that contains Reyrolle 110 kV circuit breakers and is included in the 110 kV substation redevelopment projects is presented in Table 3. Table 3 shows that the majority of the transmission circuits are critical to the reliability and security of the transmission network. This information has been used as a key input to the prioritisation of the transmission circuits programmed for replacement as part of the 110 kV substation redevelopment projects.

**Table 3 – Circuit criticality ratings**

| Circuit criticality | Circuit criticality | | | | | Total |
|---|---|---|---|---|---|---|
| | Least critical | | | | Most critical | |
| | 1 | 2 | 3 | 4 | 5 | |
| Number of circuits | 7 | 6 | 5 | 11 | 24 | 53 |
| Percentage of total | 13% | 11% | 9% | 21% | 45% | 100% |

Figure 5 presents a comparison of the criticality of the transmission circuits that contain Reyrolle 110 kV circuit breakers compared with the criticality of all transmission circuits. It shows that a large proportion of the transmission circuits that contain Reyrolle 110 kV circuit breakers tend to be critical, when compared to the entire transmission circuit population.

**Figure 5 – Reyrolle 110 kV circuit breaker comparison with the entire transmission circuit population**




## 1.6 INVESTMENT DRIVERS

This section provides a summary of the key investment drivers for the key asset categories that comprise the selected 110 kV substation redevelopment projects that have been selected for review. It is important to note that the replacement of the Reyrolle 110 kV circuit breakers is only one component of the investment need and that the timing for each of the projects is driven by a range of asset management issues. A summary of the key assets that need to be replaced as part of the 110 kV substation redevelopments are presented in Appendix A1. Appendix A highlights the particular asset categories for each transmission circuit that have been identified as being in poor condition and need to be replaced.

### 1.6.1 Supply transformers

The only 110 kV substation redevelopment project that includes the replacement of a supply transformer is the Arthurs Lake Substation redevelopment project. The Arthurs Lake Substation Condition Assessment Report (TNM-CA-809-0596) assesses the condition of the three single-phase transformers currently in service at Arthurs Lake Substation and also the identical single-phase system spare unit. The report has identified that the single-phase transformers:

(a) are critical to ensuring a secure and reliable electricity supply to customers connected to Arthurs Lake Substation;

(b) have inherent technical and design deficiencies that increase the transformers' susceptibility to major failure if subjected to fault current or over-voltage conditions;

(c) are in poor electrical and physical condition; and

(d) have reached the end of their useful lives.

The report recommends that the three single-phase units be replaced with a new three-phase unit. Following the decommissioning of transformer T1, disposal of the spare transformer located at Arthurs Lake Substation is also recommended. The transformers will be 65 years old when decommissioned.

### 1.6.2 Circuit breakers

Transend has undertaken a comprehensive review of the condition of its Reyrolle 110 kV circuit breaker population. The review has identified that the Reyrolle 110 kV circuit breakers:

(a) have a number of inherent technical and design deficiencies that have adversely impacted on transmission network reliability and availability;

(b) are unreliable, in particular the air and insulating oil systems;

(c) are maintenance intensive and costly to maintain when compared with modern equivalent units (preventive maintenance costs are approximately four times that of a modern equivalent circuit breaker);

(d) require spare parts that are no longer available from the manufacturer's agent;

(e) require skilled personnel to maintain - the availability of skilled resources is declining due to an increased staff age profile and staff turnover; and

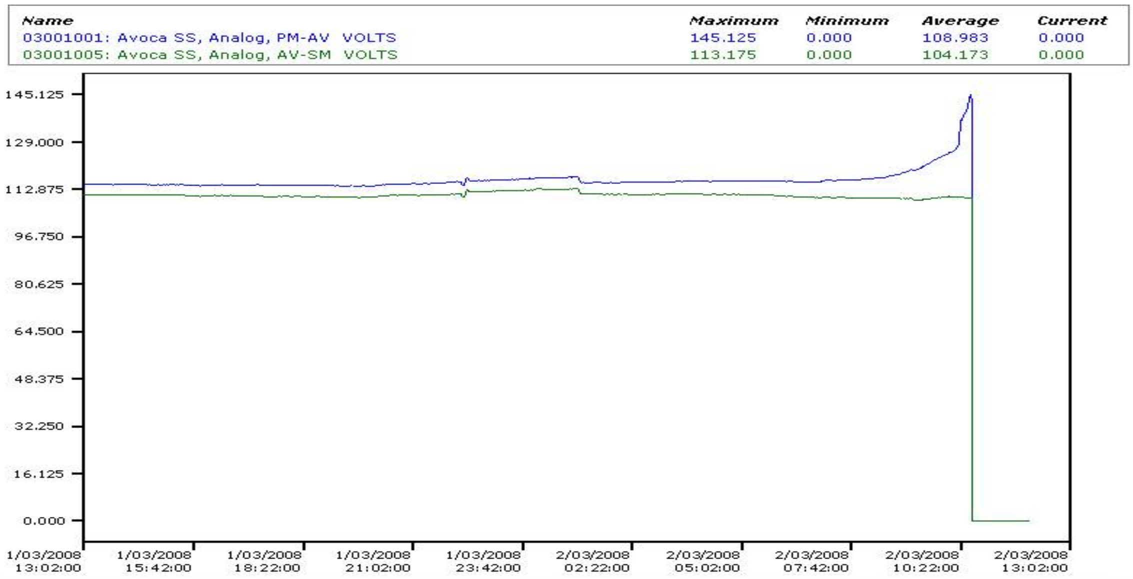
(f) have reached the end of their useful service lives.

Transend has determined the failure rates for its population of Reyrolle 110 kV circuit breakers based on their performance over the last 10 years. Transend has experienced 53 defects or failures over the last 10 years, of which four were considered major. The consequence of the defects and failures has varied from unplanned transmission circuit outages to undertake repairs to extended interruptions to electricity supply.

### 1.6.3 Instrument transformers

The ongoing serviceability of instrument transformers (this category includes current transformers, capacitive and inductive voltage transformers) is impossible to predict with certainty. With certain types of instrument transformers, Transend's experience is that maintenance does not have any material effect on preventing the occurrence of failures, in particular those that are explosive in nature. Moreover, routine condition monitoring does not always detect imminent failures. Even if it did, it is not practical, nor cost-effective to undertake the required condition monitoring activities at the frequency that would be necessary to pre-empt asset failure with any amount of certainty. Figure 6 presents an example of the voltage output profiles for two Ducon type PD 110 kV capacitive voltage transformers of the same type as those installed at Meadowbank and Palmerston substations.

**Figure 6 – Capacitive voltage transformer output voltage profiles**




The output voltage for asset 03001001 can be seen to increase dramatically within a very short period of time (within hours). This capacitive voltage transformer failed explosively, even though the condition monitoring results for this capacitive voltage transformer were satisfactory when it was last maintained. This event clearly illustrates that the risk of catastrophic failure is real and the rapid rate of deterioration that leads to explosive failure. It also highlights the negligible impact that maintenance activities have on preventing such failures, even with minimal time intervals between maintenance activities. The likelihood of instrument transformer failure increases significantly as the condition of the asset deteriorates as a consequence of ageing.

Transend notes Nuttall Consulting's view that 'The safety risks associated with the explosive failure of post type insulators and voltage transformers have been known for some time (ie circa 2000[5])'. In 1998, when Transend was established, it inherited a transmission system that had received minimal renewal investment in the preceding years. At that time it was well recognised that the transmission system required substantial investment to address the vast range of asset management issues presented by the asset base at that time. For this reason, Transend established long-term asset renewal programs that prioritised the targeted replacement of known 'high risk' assets. This approach is evidenced by the replacement of the 110 kV voltage transformers at Creek Road Substation, which, together with other targeted works, has allowed the redevelopment of the substation to be deferred by more than ten years. It should be noted that the voltage transformer and post insulator replacement programs commenced in 1999 and that Transend has replaced a large number of high risk assets in the current regulatory control period that are susceptible to explosive failure, and plans to continue to do so over the forthcoming regulatory control period. However, given the magnitude of investment required to address the identified issues and the issues associated with accessing the transmission system to undertake the required works, it is impractical to mitigate all of the risks in the short term. Effectively managing and prioritising the implementation of a complex, integrated works program has presented a considerable challenge, and will continue to do so over the forthcoming regulatory control period.

Transend's asset management policy requires that its assets be proactively managed such that they are operated safely and within prescribed technical limits.

[5] Nuttall Consulting, Review of Transend Revenue Proposal Asset Renewal Capital Expenditure, November 2008 p61

For these reasons Transend considers it vitally important that instrument transformers that are known to be in poor condition and are susceptible to failure be replaced at the appropriate time.

In addition to mitigating a serious safety risk, the replacement of instrument transformers of obsolete technology significantly reduces the need for maintenance, thereby having a positive impact on maintenance costs and increasing transmission circuit availability. Transend has identified that it is more cost-effective over the asset life-cycle to install dead-tank circuit breakers that have integral current transformers, rather than live tank circuit breakers and post-type current transformers at 110 kV. For this reason, given the condition of the Reyrolle 110 kV circuit breakers that are associated with the current transformers included in the 110 kV substation redevelopment projects, it is prudent and efficient to install dead-tank circuit breakers that incorporate current transformers rather than replace the current transformers and circuit breaker separately.

Transend's practice is to install capacitive voltage transformers (this design allows the secondary voltages to be continuously monitored) that have composite insulation and pressure relief devices incorporated into the design at 110 kV. This approach mitigates the safety risks presented by voltage transformers and reduces the maintenance need.

Transend's comprehensive strategy for the management of instrument transformers over the asset life-cycle provides significant benefits in terms of addressing significant safety and reliability issues as well as providing optimum transmission circuit availability at a low cost.

The 110 kV substation redevelopment projects include the replacement of the instrument transformer makes and types as presented in Tables 4 and 5. Of the instrument transformers identified for replacement, 60 percent will have exceeded their nominal service life of 45 years when decommissioned. The remaining units will be assessed for their suitability for re-installation elsewhere in the transmission network. Whilst age is not the sole factor for determining the need to replace instrument transformers, it provides a key indication of when the condition of the asset will have deteriorated to the extent that the likelihood of failure is increased.

**Table 4 – Replacement of current transformer makes and types**

| Current transformer make / type | Number of units | Average age (years) | Comment |
|---|---|---|---|
| Asea IMBA120 | 21 | 49 | |
| Asea Brown Boveri 236080 | 3 | 23 | The condition of these units will be assessed and if deemed serviceable, they will be installed elsewhere in the transmission network. |
| Asea Brown Boveri 236080 | 57 | 13 | These units were installed because of the need to replace units contaminated with polychlorinated biphenyl (PCB). The condition of these units will be assessed and if deemed serviceable, they will be installed elsewhere in the transmission network. |
| Laur Knudsen | 60 | 47 | |
| Endurance Electric HS | 6 | 39 | These units will be retained as spares. |
| Endurance Electric IC 115 | 3 | 48 | |
| Endurance Electric OD | 6 | 39 | These units will be retained as spares. |

| Current transformer make / type | Number of units | Average age (years) | Comment |
|---|---|---|---|
| Modern Products 09931 | 6 | 34 | These units will be retained as spares. |
| Reyrolle 015204 | 9 | 52 | |
| Tyree 06/123/16 | 6 | 30 | The condition of these units will be assessed and if deemed serviceable, they will be installed elsewhere in the transmission network. |

**Table 5 – Replacement of voltage transformer makes and types**

| Voltage transformer make / type | Number of units | Average age (years) | Comment |
|---|---|---|---|
| Asea EMFA 120 | 12 | 47 | |
| Balteau UEV110 | 6 | 31 | These units will be disposed of because of specific design issues. |
| Ducon PD | 6 | 46 | |
| Haefely Trench VEOT 123 | 6 | 22 | The condition of these units will be assessed and if deemed serviceable, they will be installed elsewhere in the transmission network. |
| Trench 123/3 | 24 | 9 | There units were installed at Creek Road Substation because of the need to replace units that were in extremely poor condition and highly susceptible to explosive failure. The condition of these units will be assessed and if deemed serviceable, they will be installed elsewhere in the transmission network. |
| Reyrolle KP5323 | 1 | 57 | |
| Ritz OTEF | 6 | 12 | The condition of these units will be assessed and if deemed serviceable, they will be installed elsewhere in the transmission network. |

### 1.6.4 Disconnectors and post insulators

The vast majority of the disconnector types associated with the 110 kV substation redevelopments are of an obsolete design that comprises many component that are in poor condition, primarily because of extensive mechanical wear over time. Many of them also have multi-piece, porcelain post insulators installed that are susceptible to failure, particularly those installed in harsh service environments. Multi-piece post insulators are susceptible to surface erosion and cracking or breaking of insulator sheds. Over time, deterioration reduces the mechanical and electrical integrity of the insulator, leading to mechanical and electrical failure.

Transend has experienced many disconnector and post insulator failures, a number of which have had potentially serious safety consequences.

Transend has adopted a condition-based approach with regard to the management of the disconnector population. If the disconnectors are expected to continue to perform reliably, and it is envisaged that they will continue to operate within their capacity, Transend's practice is to refurbish the units as appropriate, irrespective of age. The disconnector types associated with the 110 kV substation redevelopment program are presented in Table 6. The bracketed numbers indicate the disconnectors associated with the transmission bays that will not be replaced as part of the 110 kV substation redevelopments.

Table 6 indicates that 69 of the 131 disconnectors (52 per cent) will not be replaced, even though they have exceeded their nominal service lives. This clearly demonstrates that Transend has adopted a condition based approach to the management of its disconnector population and that alternatives to replacement are adopted where practicable. The disconnectors that do not need to be replaced will be refurbished, with the multi-piece post insulators replaced where practicable.

As noted in Section 1.6, Transend established a post insulator replacement program in 1999. This program has included a number of targeted post insulator replacements as well as those replaced as part of substation redevelopment projects. Transend has prioritised the program based on past performance, with consideration of the service environment in which the post insulators are located. Transend considers it vitally important that the post insulator replacement program continue as forecast to address the safety and reliability issues presented by these assets.

**Table 6 – Disconnector makes and types**

| Disconnector make / type | Number of units | Average age (years) | Comment |
|---|---|---|---|
| Asea Brown Boveri | (1)[1] | 13 | The condition of these units will be assessed and if deemed serviceable, they will be installed elsewhere in the transmission network. |
| Acelec HDB5L | 5 | 47 | |
| Acelec HDBE | 5 | 58 | |
| Essanntee 05552 | 32 | 58 | |
| Stanger DR1 | (15)[1] | 51 | |
| Stanger DR2 | 3 (42)[1] | 47 | |
| Stanger HCB | (2)[1] | 40 | These units will be retained for spare parts. |
| Stanger TTT | 16 | 55 | |
| Switchgear Pty Ltd type DBR4 | (9)[1] | 43 | |
| Taplin D751 | 1 | 26 | This unit will be retained for spare parts. |

Note 1: The numbers represented in brackets indicate the disconnectors that will be refurbished and not replaced.

### 1.6.5 Protection and control

The protection and control systems associated with the 110 kV substation redevelopment projects comprise predominately electromechanical relays, with some static devices, both types of which need to be replaced because they are susceptible to component degradation and failure, poor performance, lack of spares and have minimal functionality.

Electromechanical or static devices are obsolete technologies and require frequent maintenance and repair compared to modern microprocessor protection schemes. Transend's asset management plans for protection and control systems recommend that:

(a) protection systems that are unreliable and have exceeded their useful life be progressively replaced; and

(b) where practicable and cost-effective, protection and control system replacements should be incorporated with primary asset replacement programs.

## 1.7 CONCLUSION

Transend's revised revenue proposal is based on the following reasonable requirements for the 110 kV substation redevelopment projects associated with replacement of Reyrolle OS10 circuit breakers:

**Table 7 – Revised revenue proposal ($m 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Arthurs Lake Substation 110 kV redevelopment | - | - | 0.2 | 2.5 | 1.4 | **4.1** |
| Burnie Substation 110 kV redevelopment | - | - | 1.1 | 4.9 | 2.2 | **8.1** |
| Creek Road Substation 110 kV redevelopment | - | 1.6 | 2.7 | 22.2 | 6.6 | **33.1** |
| Knights Road Substation 110 kV redevelopment | - | - | - | 1.2 | 5.4 | **6.6** |
| Meadowbank Substation 110 kV redevelopment | - | - | - | 0.8 | 3.8 | **4.6** |
| Palmerston Substation 110 kV redevelopment | - | - | 1.8 | 8.1 | 3.8 | **13.7** |
| Temco Substation 110 kV redevelopment | - | - | - | - | 0.5 | **0.5** |
| Tungatinah Substation 110 kV redevelopment | - | - | - | 3.3 | 16.2 | **19.5** |

Further information for these projects is provided in Transend's investment evaluation summaries provided as attachments A1 to A7.

## 1.8 SECTION A – LIST OF ATTACHMENTS

| Attachment | Description |
|---|---|
| A1 | 110 kV substation transmission circuit asset replacement requirements |
| A2 | Arthurs Lake Substation redevelopment - investment evaluation summary |
| A3 | Burnie Substation 110 kV redevelopment - investment evaluation summary |
| A4 | Creek Road Substation 110 kV redevelopment - investment evaluation summary |

| Attachment | Description |
|---|---|
| A5 | Knights Road Substation 110 kV redevelopment - investment evaluation summary |
| A6 | Meadowbank Substation 110 kV redevelopment - investment evaluation summary |
| A7 | Palmerston Substation 110 kV redevelopment - investment evaluation summary |
| A8 | Tungatinah Substation 110 kV redevelopment - investment evaluation summary |

# 2 SECTION B: FARRELL AND NEW NORFOLK SUBSTATIONS SECONDARY SYSTEM REPLACEMENTS PROJECTS

## 2.1 BACKGROUND

In relation to the Farrell and New Norfolk substation secondary systems replacement projects, Nuttall Consulting considered that Transend had not demonstrated that there will be a positive net benefit in undertaking the projects in their proposed form[6]. Furthermore Nuttall Consulting argued that there is a reasonable case for the projects to be undertaken in a staged manner; prioritising the highest risk elements first. Nuttall Consulting commented that the deferment of the later stages by a number of years may offset the increased capital cost of the staged project.

In response to the draft decision, Transend accepts Nuttall Consulting's finding that the economic analysis that supported the original Farrell and New Norfolk substation secondary system replacement projects could be improved. Transend has therefore undertaken further detailed analysis, including risk assessments, to examine different staging options. This further analysis indicates that some secondary system replacement capital expenditure can be deferred. The overall extent of this capital expenditure deferral is less than recommended by Nuttall Consulting.

## 2.2 REVISED PROPOSAL

The purpose of this section is to provide further information on the Farrell and New Norfolk substation secondary systems replacement projects. Each project is discussed separately in the following sections.

### 2.2.1 Farrell Substation secondary systems replacements project

The Farrell Substation secondary systems replacements project comprises the replacement of the following protection schemes:

(a) 110 kV and 220 kV bus bar protection schemes;

(b) Sheffield–Farrell Nos. 1 and 2 220 kV transmission lines protection schemes (at Farrell and Sheffield substations);

(c) Farrell–Rosebery–Queenstown 110 kV transmission line protection scheme;

(d) Farrell–Rosebery 110 kV transmission line protection scheme;

(e) Farrell–Que–Savage River–Hampshire 110 kV transmission line protection scheme; and

(f) transformers T1 and T2 protection schemes.

The replacement of the 110 kV and 220 kV protection schemes is the highest priority components of the Farrell Substation secondary system replacements project, primarily because of the potential impact that a bus bar fault would have on the power system with either scheme out of service, the unacceptably poor performance of the existing schemes and the unavailability of spares to undertake repairs.

The Sheffield–Farrell 220 kV transmission lines provide the sole 220 kV connection between the west coast of Tasmania and the remainder of the transmission network. They connect up to 618 MW of generation to the Tasmanian power system and are frequently operated beyond their firm capacity. The distance protection schemes associated with these transmission lines comprise static relays that need to be replaced because they present a reliability risk and are obsolete technology.

[6] *Ibid*, page 65.

Over the past ten years Transend has installed modern microprocessor devices on almost all of its 32 critical 220 kV transmission lines. The Sheffield–Farrell 220 kV transmission lines are two of the three remaining critical 220 kV transmission lines that do not have modern protection schemes installed.

The replacement of the protection schemes associated with the Farrell–Rosebery–Queenstown and Farrell–Rosebery 110 kV transmission lines at Farrell Substation was primarily driven by the need for distance protection schemes that have the technical capability to allow the transmission lines to be operated in parallel. At present, the Farrell–Rosebery 110 kV transmission line supplies Rosebery Substation and the Farrell–Rosebery–Queenstown 110 kV transmission line provides a back-up supply to Rosebery Substation.

The transmission network that supplies Rosebery Substation currently does not comply with the Electricity Supply Industry (Network Performance Requirements) Regulations 2007 (network performance requirements) in that 'the unserved energy to load that is interrupted consequent on damage to a network element resulting from a credible contingency event is not to be capable of exceeding 300 MWh at any time'. The unserved energy that could result from a credible contingency event is approximately 624 MWh at Rosebery Substation, based on the 2007 load. From 2011 a further non-compliance would occur in that 'no more than 25 MW of load is to be capable of being interrupted by a credible contingency event'.

Transend therefore considers it vitally important that the protection schemes associated with the Farrell–Rosebery–Queenstown and Farrell–Rosebery 110 kV transmission lines at Farrell Substation be replaced in 2009–10 to enable Rosebery Substation to be augmented to comply with the network performance requirements.

Transend's further detailed analysis has identified that the Farrell–Que–Savage River–Hampshire 110 kV transmission line protection scheme and the transformer protection schemes replacements could be deferred at this stage.

### 2.2.2 New Norfolk Substation 110 kV protection replacements project

The New Norfolk Substation 110 kV protection replacements project comprises the replacement of the following protection schemes at New Norfolk Substation:

(a) 110 kV bus bar protection scheme;

(b) Meadowbank–New Norfolk 110 kV transmission line protection scheme;

(c) New Norfolk–Boyer Nos. 1 and 2 transmission lines protection schemes (at New Norfolk and Boyer substations);

(d) New Norfolk–Creek Road 110 kV transmission line protection scheme;

(e) New Norfolk–Chapel Street 110 kV transmission line protection scheme; and

(f) Tarraleah–New Norfolk 110 kV transmission line protection scheme.

The 110 kV bus bar protection scheme at New Norfolk Substation is a static design that was installed in 1987. It is the only one of its type in the Tasmanian transmission network. This type of bus bar protection scheme is no longer supported by the manufacturer and only limited numbers of spares are available. The bus bar protection scheme is a high impedance scheme that requires current transformer secondary circuits to be switched through disconnector auxiliary switches. Transend has standardised on the application of low impedance bus bar protection schemes at substations that have double bus bar arrangements (eg New Norfolk Substation) to avoid potential substation outages due to disconnector auxiliary switch failures. The replacement of this bus bar protection scheme has been attributed a high priority, primarily because of the criticality of the bus bar protection scheme and the unavailability of product support or spare parts.

The transmission line distance protection schemes at New Norfolk Substation comprise static relays that were installed in 1987.

The planned transmission line distance protection scheme replacements at Chapel Street, Creek Road and Meadowbank substations and Tarraleah Switching Station provide an opportunity to cost-effectively replace the transmission line distance protection schemes at New Norfolk Substation. The replacement schemes will comprise duplicated current differential schemes that will improve protection co-ordination and improve the performance of the transmission network. Transend's experience is that if the replacement of protection schemes at either end of the transmission line is undertaken years apart, there is a significant likelihood that compatible current differential relays will not be available. Given the fast rate of change in relay technology, it is prudent to replace protection schemes at both ends of a transmission line at the same time.

## 2.3 Conclusion

Transend's revised revenue proposal is based on the following reasonable requirements for the Farrell and New Norfolk substations secondary replacement projects:

**Table 8 – Revised revenue proposal ($m 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Farrell Substation secondary systems replacements | 2.0 | 6.8 | - | - | - | **8.8** |
| New Norfolk Substation 110 kV protection replacements | - | - | 0.1 | 1.3 | 4.4 | **5.8** |

Further information for these projects is provided in Transend's investment evaluation summaries provided as attachments B1 to B3.

## 2.4 Section B - List of Attachments

| Attachment | Description |
|---|---|
| B1 | Farrell Substation 110 kV and 220 kV bus bar protection scheme replacements - investment evaluation summary |
| B2 | Sheffield–Farrell 220 kV transmission lines protection schemes replacements - investment evaluation summary |
| B3 | New Norfolk Substation 110 kV protection replacements - investment evaluation summary |

# 3 SECTION C: BURNIE-WARATAH 110 kV TRANSMISSION LINE WOOD POLE REPLACEMENT PROJECT

## 3.1 BACKGROUND

In relation to the Burnie–Waratah 110 kV transmission line wood pole replacement project, Transend forecast expenditure for this project to allow for 30 structures to be replaced in 2011–12 and 40 structures in 2013–14. Unfortunately, Transend's revenue proposal should have presented the expenditure occurring in 2010–11 and 2013–14 (consistent with the three year inspection cycle). The revised revenue proposal reflects the correct timing.

Nuttall Consulting noted that recent pole inspections indicated that the poles may be in better condition than the average for their age. The replacement rates in 2004–05 (zero) and 2007–08 (12 structures or 24 poles) indicated that Transend's forecast replacement rate for the forthcoming regulatory control period was higher than appropriate. Nuttall Consulting also considered that Transend's three-year condition assessment cycle and its historical works programming made it unlikely that poles identified for replacement in 2013–14 would actually be replaced in that year, being the final year of the current regulatory control period. The draft decision therefore concluded that an allowance for the replacement of 15 structures[7] (or 30 poles) should be provided, which the AER describes in the following terms[8]:

> 'The AER consider a reduction of 50 per cent in 2011–12 and 100 per cent in 2013–14 to this project appropriately reflects the position that recent pole inspections indicate the poles are in better condition than average for their age.'

In response to the draft decision, Transend understands that Nuttall Consulting's findings were partly based on recent patterns of pole replacement. In particular, Nuttall Consulting noted that zero poles were identified in 2007–08 as requiring replacement and only 12 structures or 24 poles were condemned in 2004–05. Transend accepts that this recent experience appears to justify a lower replacement program than proposed by Transend. However, Transend's view is that a longer time series analysis supports Transend's initial forecast rate of replacement.

Transend's practice is to replace condemned poles within three months of the inspection, which is scheduled for the end of March. Therefore, any condemned poles in the 2013–14 year will be replaced during the current regulatory control period. In light of the historical rate of pole replacement, Transend does not accept the AER's view that no poles will need to be replaced in 2013–14. Transend's view is that a prudent and efficient operator would have regard to past requirements for replacement, together with ongoing condition assessment data, when projecting future pole replacements.

Transend has reviewed its original proposal for pole replacements and maintains its view that this forecast, adjusted for the correct timing, is reasonable. This section provides further information about the revised revenue proposal for the Burnie–Waratah 110 kV transmission line wood pole replacement project.

## 3.2 REVISED PROPOSAL

### 3.2.1 Requirements for pole replacement

Transend's forecast pole replacement requirements are reliant upon typical pole replacement rates advised by Aurora Energy.

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7 It should be noted that page 104 of the draft decision actually states that an allowance for 15 poles should be provided. Transend believes that this is a drafting error and should refer to 15 structure or 30 poles. Nuttall Consulting report, page 66, correctly refers to 15 structures.

8 *Ibid*, page 319.

This replacement rate has been determined by Aurora over a 40 year period for an asset base including over 250,000 wood poles and hence can be considered statistically valid. Further information regarding actual and forecast wood pool failure rates is provided in the Burnie–Waratah 110 kV transmission line wood poles condition assessment report, provided as Attachment C2.

The historical replacement rate suggests that Transend is likely to require pole replacements at a rate of approximately 10 poles per year. As there were no condemned poles identified in 2007–08, it is likely that a larger number of poles will be identified for replacement in the next period than would normally be observed. As the last pole to be condemned was identified in 2004–05, it is estimated that 70–80 poles will require replacement in the 2009–13 revenue period.

There is always some level of uncertainty when predicting whether both poles comprising a tower structure will be condemned, or whether only one of the two poles will be condemned. Regardless, for suspension structures, it is Transend's policy to replace both poles with a single steel pole. Strain structures are replaced by two steel poles. Allowing for a number of structures where both poles are found to be condemned, Transend estimates that 70 structures will require replacement in the 2009–13 revenue period. To reduce this program by 50 per cent (as proposed by the AER) would increase the likelihood of structure failure at numerous sites, significantly increasing the safety, environmental and reliability risk to both Transend and the community.

### 3.2.2 Timing of pole replacement

Transend has considered the issue raised by the AER with respect to the replacement timing following identification of a condemned structure. In 2006 Transend reviewed its wood pole replacement strategy. This review resulted in Transend implementing a three yearly inspection cycle for all wood poles (as is also utilised by Aurora Energy). Due to potentially poor access track conditions during the wetter winter months Transend adopted an approach whereby pole inspections occur during summer.

Where a condemned pole is identified, Transend also adopted a requirement to ensure that condemned poles are replaced prior to the onset of the expected wet weather winter period. To maximise the likelihood of this replacement occurring in the appropriate timeframe, Transend specified that all pole replacements occur within three months of identification.

To leave a pole replacement until after winter (as has been suggested by the AER for any condemned poles identified in the 2013–14 inspection cycle) would raise the likelihood of a pole failure, increasing the safety, environmental and reliability risk to Transend and the community to unacceptable levels. Undertaking repairs in winter would increase the time (and costs) required to repair the transmission line because of additional access issues created by wet conditions.

Hence Transend is strongly of the opinion that funding must be made available for wood pole replacements in 2013–14, and that this funding cannot be deferred until the following revenue period.

### 3.2.3 Correction of typographical error

The AER draft proposal reflects a typographical error in Transend's submission and shows Transend wood pole replacement expenditure occurring in 2011–12. The expenditure should actually be shown as being incurred in the 2010–11 financial year to ensure alignment with Transend's three yearly inspection cycle.

### 3.2.4 Conclusion

Transend's revised revenue proposal is based on the following reasonable requirements for the Burnie–Waratah 110 kV transmission line wood pole replacements:

**Table 9 – Revised revenue proposal ($m 2008–09)**

| | 2009–10 | 2010–11 | 2011–12 | 2012–13 | 2013–14 | Total |
|---|---|---|---|---|---|---|
| Burnie–Waratah 110 kV transmission line wood pole replacements | - | 2.5 | - | - | 3.3 | **5.8** |

Further information for the Burnie–Waratah 110 kV transmission line wood pole replacement project is provided in Transend's investment evaluation summary (Attachment C1) and Transend's condition assessment report (Attachment C2).

## 3.3 List of Attachments

| Attachment | Description |
|---|---|
| C1 | Burnie–Waratah 110 kV transmission line wood pole replacements - investment evaluation summary |
| C2 | Burnie–Waratah 110 kV transmission line wood poles - condition assessment report |

# ATTACHMENT A1 – 110 KV SUBSTATION TRANSMISSION CIRCUIT ASSET REPLACEMENT REQUIREMENTS

| Substation | Designation | Circuit | Reyrolle circuit breakers | Current transformers | Voltage transformers | Disconnectors | Post insulators | Protection and control schemes |
|---|---|---|---|---|---|---|---|---|
| Arthurs Lake | Palmerston - Arthurs lake 110kV T/L (T1 circuit) | A1 | ✓ | ✓ | | | ✓ | ✓ |
| | | | | | | | | |
| Burnie | Burnie - Emu Bay 110kV T/L | D1 | ✓ | ✓ | | | | ✓ |
| Burnie | Burnie - Hampshire 110kV T/L | K1 | ✓ | ✓ | | | | ✓ |
| Burnie | Bus Coupler | B7 | ✓ | ✓ | | | | |
| Burnie | Sheffield - Burnie No 2 110kV T/L | E1 | ✓ | ✓ | | | | |
| Burnie | Burnie - Smithon 110kV T/L | J1 | ✓ | ✓ | | | | |
| Burnie | T3 | C5 | ✓ | ✓ | | | | |
| Burnie | T2 | B5 | ✓ | | | | | |
| | | | | | | | | |
| Creek Road | Bus Coupler | D7 | ✓ | ✓ | | ✓ | ✓ | ✓ |
| Creek Road | Bus Coupler | C7 | ✓ | | | | ✓ | ✓ |
| Creek Road | Bus Coupler | F7 | ✓ | | | | ✓ | ✓ |
| Creek Road | Creek Road - North Hobart No1 110kV T/L | L1 | ✓ | | | ✓ | ✓ | ✓ |
| Creek Road | Bus Coupler | A7 | ✓ | | | | ✓ | |
| Creek Road | Creek Road - North Hobart No2 110kV cable | M1 | ✓ | | | ✓ | ✓ | ✓ |
| Creek Road | Chapel Street - Creek Road No2 110kV T/L | E1 | ✓ | ✓ | | ✓ | ✓ | ✓ |
| Creek Road | Bus Coupler | G7 | ✓ | | | | ✓ | ✓ |
| Creek Road | New Norfolk -Creek Road 110kV T/L | B1 | ✓ | | ✓ | ✓ | ✓ | |
| Creek Road | Chapel Street - Creek Road No1 110kv T/L | D1 | ✓ | | | ✓ | ✓ | ✓ |
| Creek Road | Chapel Street - Creek Road - Risdon | K1 | ✓ | | | ✓ | ✓ | ✓ |
| Creek Road | T2 | B4 | ✓ | | | ✓ | ✓ | |
| Creek Road | T4 | D4 | ✓ | | | ✓ | ✓ | |
| Creek Road | T3 | C4 | ✓ | | | | ✓ | |
| Creek Road | T1 | A4 | ✓ | | | | ✓ | |
| Creek Road | Contingency bay | G1 | ✓ | | | | ✓ | |
| | | | | | | | | |
| Knights Road | Bus Coupler | A7 | ✓ | ✓ | ✓ | | ✓ | ✓ |
| Knights Road | Knights Road - Electrona 110kV T/L | A1 | ✓ | ✓ | | | ✓ | ✓ |
| Knights Road | Knights Road - Huon River - Kermandie 110kV T/L | J1 | ✓ | ✓ | | | ✓ | |
| Knights Road | Chapel Street - Kingston - Knights Road 110kV T/L | C1 | ✓ | ✓ | | | ✓ | ✓ |
| Knights Road | T2 | B4 | ✓ | | | | ✓ | ✓ |
| | | | | | | | | |
| Meadowbank | T4 (110/ 22kV) | A4 | ✓ | ✓ | ✓ | | ✓ | ✓ |
| Meadowbank | Tarraleah - Meadowbank 110kV T/L | A1 | ✓ | ✓ | | | ✓ | ✓ |
| Meadowbank | Meadowbank - New Norfolk 110kV T/L | B1 | ✓ | ✓ | | | ✓ | ✓ |
| | | | | | | | | |
| Palmerston | Bus Coupler | B7 | ✓ | ✓ | | | ✓ | ✓ |
| Palmerston | Palmerston - Avoca 110kV T/L | R1 | ✓ | ✓ | | | ✓ | ✓ |
| Palmerston | Palmerston - Arthurs lake 110kV T/L | O1 | ✓ | ✓ | | | ✓ | ✓ |
| Palmerston | Palmerston - Hadspen No 4 110kV T/L | Z1 | ✓ | ✓ | | | ✓ | ✓ |
| Palmerston | Palmerston - Hadspen No 3 110kV T/L | Y1 | ✓ | ✓ | | | ✓ | ✓ |
| Palmerston | Poatina - Palmerston No 2 110kV T/L | M1 | ✓ | ✓ | | | ✓ | |
| Palmerston | Waddamana - Palmerston No2 110kV T/L | P1 | ✓ | ✓ | | | ✓ | |
| Palmerston | Poatina - Palmerston No 1 110kV T/L | N1 | ✓ | ✓ | | | ✓ | |
| Palmerston | T1 | A5 | ✓ | | | | ✓ | |
| Palmerston | T4 | D4 | ✓ | ✓ | | | ✓ | |
| Palmerston | T3 | C4 | ✓ | ✓ | | | ✓ | |
| | | | | | | | | |
| Rosebery | T1 | A4 | ✓ | | | ✓ | ✓ | ✓ |
| | | | | | | | | |
| Tarraleah | Bus Coupler | 7 | ✓ | | | ✓ | ✓ | ✓ |
| Tarraleah | Tarraleah - New Norfolk No1 110kV T/L | B1 | ✓ | | ✓ | ✓ | ✓ | ✓ |
| Tarraleah | Tarraleah - New Norfolk No2 110kV T/L | D1 | ✓ | | ✓ | ✓ | ✓ | ✓ |
| Tarraleah | Tarraleah - Meadowbank 110kV T/L | C1 | ✓ | | | ✓ | ✓ | ✓ |
| Tarraleah | Tarraleah - Tungatinah No1 110kV T/L | E1 | ✓ | | | ✓ | ✓ | ✓ |
| Tarraleah | Tarraleah - Tungatinah No2 110kV T/L | F1 | ✓ | | | ✓ | ✓ | ✓ |

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | ARTHURS LAKE SUBSTATION REDEVELOPMENT |
| **TRIM REFERENCE** | D09/3853 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 2.0 |
| **TRANSEND CONTACT** | GEOFF FLACK |
| **PROJECT NUMBER** | ND0910 |

## ATTACHMENT A2

# CONTENTS

# 1 BACKGROUND

Arthurs Lake Substation is critical to ensuring a secure and reliable electricity supply to the central highlands area of Tasmania. The substation supplies electricity to Hydro Tasmania's pumping station, which pumps water from Arthurs Lake into Great Lake. The substation also provides a connection point to Aurora Energy via a 6.6 kV feeder which is stepped-up to 22 kV by a 6.6/22 kV transformer that is also owned by Aurora Energy.

Arthurs Lake Substation is located within metres of Arthurs Lake and is adjacent to camping and boating facilities. The area around the substation is frequently accessed by the public for recreational purposes. In addition, the substation is located within the Central Plateau Conservation Area and as such is considered to be an environmentally sensitive site.

Figure 1 presents the schematic diagram of the northern Tasmanian transmission network that connects to Arthurs Lake Substation.

**Figure 1 - Northern area transmission network schematic diagram**

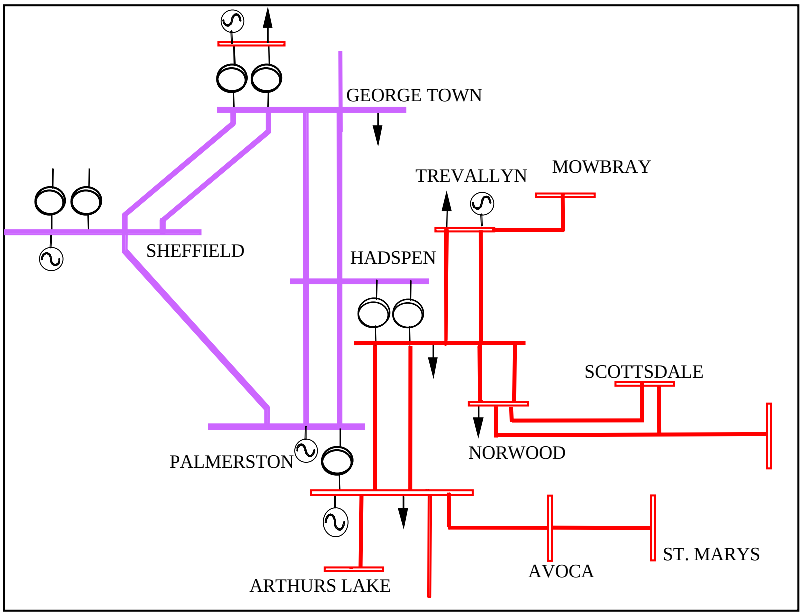


Figure 2 presents an aerial view of Arthurs Lake Substation and clearly shows its close proximity to Arthurs Lake. The access road to the public boat ramp can be seen on the right hand side of the image.

**Figure 2 – Aerial view of Arthurs Lake Substation**

# 2 PROJECT OVERVIEW

The planned redevelopment of Arthurs Lake Substation primarily includes the replacement of the three single phase 110/6.6 kV supply transformers, 110 kV circuit breaker, current transformers, post insulators and protection and control equipment. The substation redevelopment will improve the security and reliability of electricity supply by replacing assets that are in poor condition and susceptible to failure.

This project comprises the following works at Arthurs Lake Substation:

- replacement of the existing 110/6.6 kV single-phase transformers with a three-phase transformer;
- replacement of the transformer oil containment system with a fully compliant system;
- replacement of the Reyrolle type 110/OS/10 circuit breaker;
- decommissioning of the existing post type current transformers;
- replacement of multi-piece post insulators;
- replacement of all 6.6 kV assets (excluding circuit breaker A352);
- replacement of protection and control schemes; and
- upgrade of the switchyard earthing system to address identified earthing issues.

The vast majority of assets included in the Arthurs Lake Substation redevelopment project are well beyond their nominal service lives of 45 years for primary assets and 15 years for secondary assets as defined by Sinclair Knight Merz in its 'Assessment of Economic Lives for Transend Regulatory Asset Classes' report prepared in April 2008 provided as attachment 24 of Transend's revenue proposal. The majority of the primary assets at Arthurs Lake Substation will be over 53 years old when replaced (the supply transformers will be 65 years old).

# 3 PROJECT TIMING

The timing of this project has been co-ordinated with the prioritised supply transformer and 110 kV circuit breaker replacement programs.

The project is currently scheduled to commence in 2012 and be completed in 2014.

# 4 INVESTMENT NEED

## 4.1 SUMMARY

This project is required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the National Electricity Rules (Rules):

- maintain the quality, reliability and security of supply of prescribed transmission services; and
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

The key investment drivers for this project are to address identified safety, condition and performance issues presented by the primary and secondary assets at Arthurs Lake Substation.

## 4.2 SUPPLY TRANSFORMERS

Transformer T1 at Arthurs Lake Substation comprises three 4 MVA single-phase units that were manufactured in 1949. The units were originally installed at Shannon Power Station and were moved to Arthurs Lake Substation following the decommissioning of the power station in 1964. The 110/6.6 kV transformers are unique and are the only remaining single-phase transformers remaining in the transmission system. There has been no major work carried out on these transformers.

The Arthurs Lake Transformer T1 Condition Assessment Report (TNM-CR-806-0889) assesses the condition of the three single-phase transformers currently in service at Arthurs Lake Substation and also the identical single-phase system spare unit. The report has identified that the transformers:

- are critical to ensuring a secure and reliable electricity supply to customers connected to Arthurs Lake Substation;
- have inherent technical and design deficiencies that increase the transformers' susceptibility to major failure if subjected to fault current or over-voltage conditions;
- are in poor electrical and physical condition; and
- have reached the end of their useful lives.

The report recommends that the three single-phase units be replaced with a new single-phase unit. Following the decommissioning of transformer T1, disposal of the spare transformer located at Arthurs Lake Substation is also recommended.

The 110 kV supply transformers installed at Arthurs Lake Substation will be 65 years old when decommissioned.

## 4.3 CIRCUIT BREAKER

The 110 kV circuit breaker installed at Arthurs Lake Substation is a Reyrolle type 110/OS/10 unit manufactured in 1962. The Reyrolle Type 110/OS/10 110 kV Circuit Breaker Condition Assessment Report (TNM CR 806 0772) assesses the condition of Reyrolle type 110/OS circuit breakers and recommends that the unit at Arthurs Lake Substation be replaced. The circuit breaker assessment has been based on key asset management considerations, including technical, design, reliability, condition, maintenance, spares and contingency planning, life-cycle and environment issues. The report has identified that Reyrolle type 110/OS/10 circuit breakers:

- have a number of inherent technical and design deficiencies that have adversely impacted transmission circuit reliability and availability;
- are unreliable, in particular the air and insulating oil systems;
- are maintenance intensive and costly to maintain when compared with modern equivalent units;
- require spare parts that are no longer available from the manufacturer's agent;
- require skilled personnel to maintain - the availability of specialised maintenance resources is declining; and
- have reached the end of their useful service lives.

All other transmission companies in Australia and New Zealand have already replaced their population of Reyrolle type 110/OS/10 circuit breakers, or are in the process of doing so, for the same reasons outlined above. Transend's reasons for replacing this type of circuit breaker are no different to those of other industry participants.

The 110 kV circuit breaker installed at Arthurs Lake Substation will be 52 years old when decommissioned.

The preventive maintenance costs associated with the 110 kV circuit breaker at Arthurs Lake Substation include:

- circuit breaker maintenance: $9 900 (six yearly);
- insulating oil costs: $4 200 (six yearly);
- compressor maintenance: $1 000 (six-monthly for the compressor at Arthurs Lake Substation);
- silica gel maintenance: $500 (two yearly); and
- pressure inspection costs: $300 (three yearly).

In addition, the average historic repair cost for a failure or defect associated with a Reyrolle type 110/OS/10 circuit breaker is $4 730.

## 4.4 CURRENT TRANSFORMERS

The 110 kV current transformers (three single phase units) installed at Arthurs Lake Substation are Laur Knudsen type A8ZX units that were manufactured in 1962. A number of identical current transformers installed elsewhere in the transmission network have been identified as having high percentage power factor readings. This type of current transformer utilises a silica gel breather that requires the transmission circuit to be removed from service for maintenance. This deficiency impacts adversely on transmission circuit availability.

The Current Transformer Asset Management Plan (TNM-PL-809-0605) recommends that the Laur Knudsen type A8ZX current transformers be progressively replaced with current transformers installed with the dead-tank circuit breakers because they are generally in poor condition and require frequent maintenance in comparison to modern equivalent units.

The current transformers will be 52 years old when decommissioned.

The average preventive maintenance costs associated with 110 kV current transformers at Arthurs Lake Substation is $5 500 per three phase set.

## 4.5 HIGH VOLTAGE ASSETS

The major issues associated with 6.6 kV assets installed at Arthurs Lake Substation (including the disconnector, voltage transformer, bus conductor and station services transformers) relate to the gross non-compliance of the installation with Australian Standard AS 2067-1984, 'Switchgear Assemblies and Ancillary Equipment for Alternating Voltages Above 1 kV' (AS 2067). The exposed, sub-standard high voltage assets presents a significant risk to employees, contractors and the public. In addition, the installation is susceptible to vandalism and unplanned outages due to wildlife interacting with live equipment.

The likelihood of inadvertent human contact with electrical equipment is a key risk given the proximity of Arthurs Lake Substation to public recreational areas.

## 4.6 PROTECTION AND CONTROL SYSTEMS

The protection and control systems at Arthurs Lake are all electromechanical type relays installed in early 1960s. Of the 12 protection relays at Arthurs Lake Substation, two were found to be faulty during routine tests in 2006. The A164 RPL type EL15 earth fault protection relays was found to be non-operational, the impact of this fault would have been a delayed clearance hence additional plant damage for 110 kV faults at Arthurs Lake Substation. The A379 English Electric type VAR42 relay was also found to be faulty, this would have resulted in temporary feeder faults causing extended circuit outages.

The relays at Arthurs Lake Road Substation:

- are of obsolete technology;
- are no longer supported by their manufacturer;
- do not capture disturbance records for fault analysis;
- do not have self-diagnostic features; and
- require testing and maintenance on a more frequent basis than modern equivalent assets.

The relevant protection and control asset management plans recommend the replacement of these obsolete electromechanical devices.

## 4.7 OIL CONTAINMENT

The oil containment system at Arthurs Lake Substation comprises a temporary ‘Hypalon’ bund and is not designed to meet current standards. The single-phase units are also not separated by blast-walls. There is a significant risk that, in the event of a major transformer failure, considerable environmental damage could be caused due to loss of oil off-site and significant damage to adjacent equipment could occur because of the lack of blast wall facilities.

**Oil bunding**

The following design issues have been identified with Hypalon oil bunding systems:

- there is a single bund area for multiple transformers. Due to the common bund area, in the event of an oil fire, the oil (and possibly fire) can easily spread to the adjacent transformers;
- the Hypalon bund area does not have a flame trap installed, increasing the chances of a transformer fire spreading to the oil containment tank; and
- a blue metal layer covers the Hypolon bund in order to ensure a non-slip surface. This presents the following issues:
    - it limits the flow of insulating oil in the bund and increases the risk of a high-intensity fire around the transformer;
    - it reduces the visibility of the Hypalon layer when carrying out routine condition assessments. Any cracks or damage to Hypalon layer will not be identified during these condition assessments; and
    - it may not provide sufficient drainage for the oil and the water introduced during fire fighting. This could lead to overflow of the oil from the bunded area.

Transend commenced a replacement program for its population of Hypalon bunds to address the issues associated with the Hypalon bund. The Hypalon bund at Arthurs Lake Substation will be replaced with a fully compliant concrete bund.

**Oil containment tanks**

The oil containment tanks are physically situated in a fenced enclosure adjacent to the main Substation yard. The oil containment tanks are in very poor condition as shown by the external cracks evident in Figure 4. In addition, the tanks are positioned above ground, which makes them vulnerable to vandalism. The tanks are located within metres of Arthurs Lake, which increases the risk of a significant environmental incident should the tanks fail to contain insulating oil in the event of an oil spill within the transformer bund.

# 5 CUSTOMER CONSULTATION

Transend will liaise directly with relevant stakeholders regarding the intent, scope and implementation of the project as part of the project initiation process.

# 6 BENEFITS

The direct benefits that are achieved through completing the work outlined in the scope of this project are:

- contributing to the achievement of the capital expenditure objectives identified in the Rules;
- substantially reduce identified safety and environmental risks associated with the existing assets;
- provision of a safe, secure and reliable electricity supply to customers connected to Arthurs Lake Substation by replacing obsolete, unreliable assets that are in poor condition;
- life-cycle cost savings due to reduced operations and maintenance requirements;
- reduced burden on spare parts management by using standard equipment; and
- alignment with strategic asset management plans.

# 7 OPTIONS ANALYSIS

The following options have been considered for the redevelopment of Arthurs Lake Substation:

1. staged redevelopment;
2. replace selected assets in-situ;
3. replace all assets in situ; and
4. replace all assets at a greenfield location.

## 7.1 OPTION 1: STAGED REDEVELOPMENT

### 7.1.1 SCOPE

The scope for this option includes:

- replacement of assets that present a safety or environmental risk, including identified 6.6 kV switchgear, earthing systems, oil containment system, 110 kV post insulators and current transformers in 2014;
- replacement of supply transformer T1 due to condition in 2014;
- continue existing maintenance practices for remaining assets, albeit accelerated due to the declining condition and ageing of assets;
- undertake repairs and corrective maintenance as required; and
- defer replacement of 110 kV circuit breaker and associated protection for up to five years.

The capital cost of this option includes an initial $2.70 million ($June 2007) to address safety issues followed by a deferred capital cost of $0.85 million ($June 2007) to replace remaining 110 kV assets five years later.

### 7.1.2 BENEFITS

The benefits for this option are the deferral of capital expenditure and that the identified safety and environmental issues are addressed.

### 7.1.3 DRAWBACKS

The drawbacks for this option are that it would:

- not allow Transend to achieve the capital expenditure objectives;
- not satisfactorily address the performance issues identified in section 4 of this document;
- not be sustainable given the demonstrated reliability issues associated with the 110 kV primary and secondary assets;
- result in an increased number of loss of electricity supply events at Arthurs Lake Substation when compared with other options;
- incur significantly longer and more frequent outages due to the intensive maintenance regimes that would be required to sustain the existing assets in service (whilst recognising that this approach is almost certainly unlikely to be successful);
- incur increased ongoing operating expenditure due to increased maintenance, condition monitoring and corrective maintenance requirements;
- not align with Transend's policy to utilise dead tank circuit breakers when replacing 110 kV live tank current transformers and circuit breakers; and
- not align with the recommendations made in respective asset management plans for the primary and secondary assets.

### 7.1.4 CONCLUSION

Although this option has lower initial capital cost, it is not the preferred option because it does not ensure the reliable operation of Arthurs Lake Substation.

## 7.2 OPTION 2 - REPLACE SELECTED ASSETS IN-SITU

### 7.2.1 SCOPE

The scope for this option includes the replacement of the following assets in 2014:

- replacement of assets that present a safety, environmental and compliance risk, including identified 6.6 kV switchgear, earthing systems, oil containment system and multi-piece post insulators;
- replacement of the three single-phase supply transformers with a new three-phase unit;
- replacement of the existing live tank circuit breaker with dead tank unit that has integral current transformers;
- replacement of the identified protection and control schemes; and

- implementation of revised maintenance practices.

The capital cost of this option is $3.24 million ($June 2007).

#### 7.2.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;
- addresses the safety, environmental and performance issues associated with the 110 kV assets as identified in section 4 of this document;
- reduces the maintenance requirements and costs associated with the site.

#### 7.2.3 DRAWBACKS

The option has the following drawbacks:

- higher initial capital cost than option 1.

#### 7.2.4 CONCLUSION

This option is technically viable.

### 7.3 OPTION 3 - REPLACE ALL ASSETS IN-SITU

#### 7.3.1 SCOPE

The scope for this option includes the replacement of the following assets in 2014:

- replacement of assets that present a safety, environmental and compliance risk, including identified 6.6 kV switchgear, earthing systems, oil containment system and multi-piece post insulators;
- replacement of the three single-phase supply transformers with a new three-phase unit;
- replacement of the existing live tank circuit breaker with dead tank unit that has integral current transformers;
- replacement of 6.6 kV circuit breaker;
- replacement of 110 kV disconnector;
- replacement of the identified protection and control schemes; and
- implementation of revised maintenance practices.

The capital cost of this option is $3.40 million ($June 2007).

#### 7.3.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;

- addresses the safety, environmental and performance issues associated with the 110 kV assets as identified in section 4 of this document;
- reduces the maintenance requirements and costs associated with the site.

#### 7.3.3 Drawbacks

The option has the following drawbacks:

- higher initial capital cost than options 1 and 2.

#### 7.3.4 Conclusion

This option is technically viable.

### 7.4 OPTION 4 - REPLACE ALL ASSETS AT A GREENFIELD LOCATION

#### 7.4.1 Scope

The scope for this option includes the replacement of all 110 kV and 6.6 kV assets at a greenfield location in 2014. The capital cost of this option is $6.87 million ($June 2007).

#### 7.4.2 Benefits

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;
- addresses the safety, environmental and performance issues associated with the 110 kV assets as identified in section 4 of this document;
- reduces the maintenance requirements and costs associated with the site.

#### 7.4.3 Drawbacks

The option has the following drawbacks:

- higher initial capital cost than other options.

#### 7.4.4 Conclusion

This option is technically viable.

## 8 OPTION ESTIMATES

Economic analysis of the asset management options has been undertaken to confirm the cost-benefits associated with each option. Table 1 presents a summary of the net present value (NPV) of costs for each option.

**Table 1 - Summary of economic analysis of options**

| Option | Net present value of costs ($M June 2007) |
|---|---|
| 1. Maintain existing assets and defer replacement | $1.97 |
| 2. Replace selected assets in-situ | $1.91 |
| 3. Replace all assets in-situ | $1.98 |
| 4. Replace all assets in a Greenfield location | $3.62 |

The economic analysis includes the cost impact to customers in the event of a major circuit breaker failure using a probabilistic approach based on current and forecast load data the transmission circuit connected to Arthurs Lake Substation.

# 9 PREFERRED OPTION

Option 2 is preferred because it addresses the issues identified in section 4 at the least cost.

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | BURNIE SUBSTATION 110 KV REDEVELOPMENT |
| **TRIM REFERENCE** | D08/40763 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 2.0 |
| **TRANSEND CONTACT** | ALAN BROWN |
| **PROJECT NUMBER** | ND0908 |

## ATTACHMENT A3

# CONTENTS

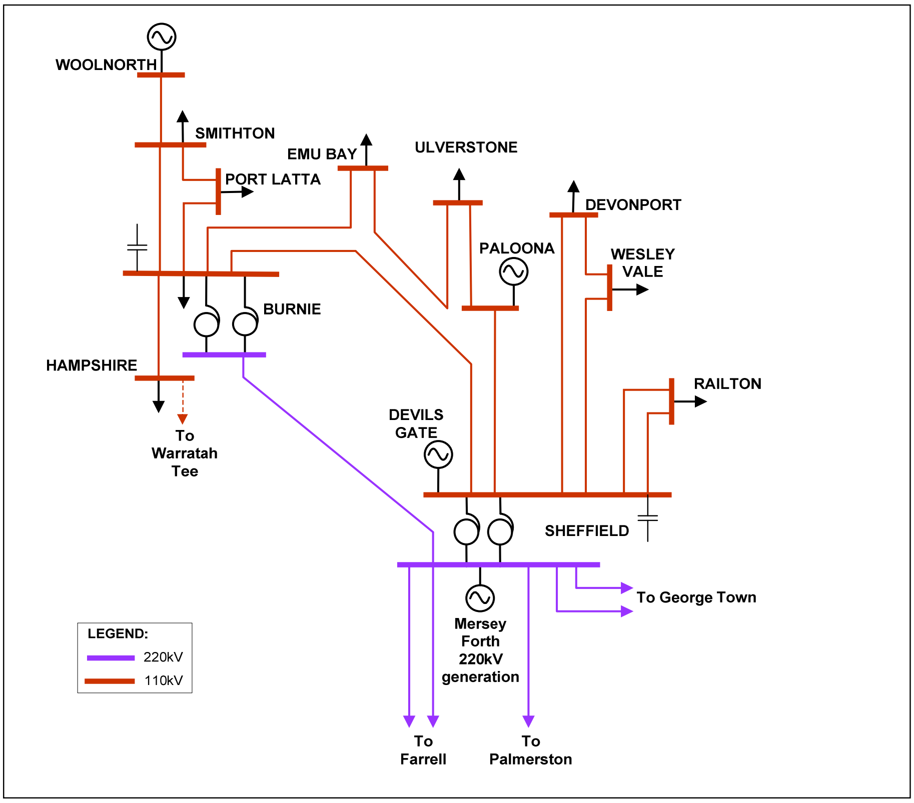
# 1 BACKGROUND

Burnie Substation is critical to ensuring a secure and reliable electricity supply to customers in north-west Tasmania. Burnie Substation 110 kV provides:

- an interconnection to Burnie Substation 220 kV via two 90 MVA auto-transformers (these transformers are currently being replaced with a single transformer under a separate project);
- transmission lines to Emu Bay, Hampshire (radial), Port Latta, Sheffield and Smithton substations; and
- two 110/22 kV transformers that supply connections to Aurora Energy.

Figure 1 presents the schematic diagram of the north-west Tasmanian transmission network that connects to Burnie Substation.

**Figure 1 – North-west area transmission network schematic diagram**




The majority of the 110 kV assets in service at Burnie Substation were installed when the substation was commissioned in 1952.

# 2 PROJECT OVERVIEW

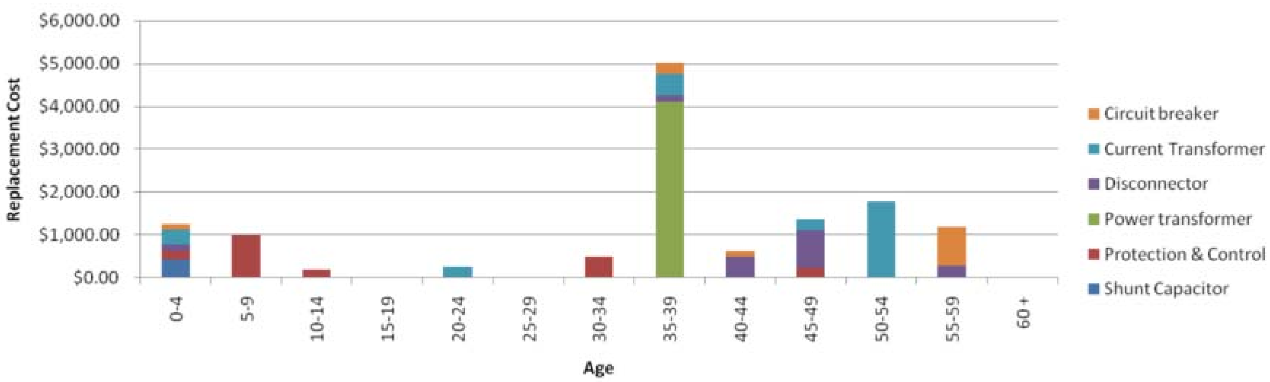
The planned redevelopment of Burnie Substation 110 kV primarily includes the replacement of 110 kV circuit breakers, current transformers, and protection and control equipment and the installation of voltage transformers. The substation redevelopment will improve the security and reliability of electricity supply by replacing assets that are in poor condition and susceptible to failure.

This project comprises the following works at Burnie Substation:

- replacement of five Reyrolle type 110/OS/10 circuit breakers with dead tank circuit breakers that have integral current transformers;
- replacement of three Sprecher and Schuh type HPFw-311-L circuit breakers with dead tank circuit breakers that have integral current transformers;
- decommissioning of the existing post type current transformers;
- installation of five three-phase sets of voltage transformers;
- replacement of the Burnie–Emu Bay 110 kV transmission line protection;
- replacement of the Burnie–Hampshire 110 kV transmission line protection;
- replacement of the Sheffield–Burnie No 2 110 kV transmission line protection; and
- replacement of the bus-coupler protection.

Figure 3 provides a summary of the age of the 110 kV assets (by category) at Burnie Substation by asset replacement cost of (note that the scope of this project excludes replacement of power transformers, post insulators, disconnectors, selected protection and control systems and shunt capacitors). Figure 3 clearly illustrates that the vast majority of the assets included in the Burnie Substation 110 kV redevelopment project are well beyond their nominal service lives of 45 years for primary assets and 15 years for secondary assets as defined by Sinclair Knight Merz in its 'Assessment of Economic Lives for Transend Regulatory Asset Classes' report prepared in April 2008 provided as attachment 24 of Transend's revenue proposal.  The majority of the primary assets at Burnie Substation will be over 55 years old when replaced (the circuit breakers will be 62 years old).

**Figure 2 - Age and replacement value ($000) of major equipment installed at Burnie Substation**




# 3 PROJECT TIMING

The timing of this project has been co-ordinated with the prioritised 110 kV circuit breaker replacement program and the overall capital works program. This project is currently ranked 28th of all projects in Transend's works prioritisation tool and 11th of all renewal projects. The project is currently scheduled to commence in 2011 and be completed in 2014.

It is likely that components of this project may need to be implemented prior to the planned commencement of the project because of the deteriorated condition of certain assets and the fact that additional asset condition issues will most likely be identified prior to commencement of the project. It should be noted that these works, should they be needed, will not result in the need for significant rework because the substation is not being reconfigured.

# 4 INVESTMENT NEED

This project is required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the National Electricity Rules (Rules):

- maintain the quality, reliability and security of supply of prescribed transmission services; and
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

The key investment drivers for this project are to address identified safety, condition and performance issues presented by the primary and secondary assets at Burnie Substation 110 kV.

## 4.1 CIRCUIT BREAKERS

The 110 kV circuit breakers at Burnie Substation comprise the following types:

- Reyrolle type 110/OS/10 circuit breakers; and
- Sprecher and Schuh type HPFw-311-L circuit breakers.

**Reyrolle type 110/OS/10 circuit breakers**

There are seven Reyrolle type 110/OS/10 units installed at Burnie Substation. The Reyrolle Type 110/OS/10 110 kV Circuit Breaker Condition Assessment Report (TNM-CR-806-0772) recommends that the units at Burnie Substation be replaced. The circuit breaker condition assessment has been based on key asset management considerations including technical, design, reliability, condition, maintenance, spares and contingency planning, life-cycle and environmental issues. The condition assessment report also provides details of the many failures and defects associated with Reyrolle 110 kV circuit breakers, including those installed at Burnie Substation. The condition assessment report has identified that Reyrolle type 110/OS/10 circuit breakers:

- have a number of inherent technical and design deficiencies that have adversely impacted transmission circuit reliability and availability;
- are unreliable, in particular the air and insulating oil systems;
- are maintenance intensive and costly to maintain when compared with modern equivalent units;
- require spare parts that are no longer available from the manufacturer’s agent;
- require skilled personnel to maintain - the availability of specialised maintenance resources is declining; and
- have reached the end of their useful service lives.

All other transmission companies in Australia and New Zealand have already replaced their population of Reyrolle type 110/OS/10 circuit breakers, or are in the process of doing so, for the same reasons outlined above. Transend’s reasons for replacing this type of circuit breaker are no different to those of other industry participants.

The 110 kV circuit breakers at Burnie Substation will be 62 years old when replaced.

The preventive maintenance costs associated with the 110 kV circuit breakers at Burnie Substation include:

- circuit breaker maintenance: $7 600 per circuit breaker (six yearly);
- insulating oil costs: $4 200 per circuit breaker (six yearly);
- compressor maintenance: $1 000 per compressor (six-monthly for the two compressors at Burnie Substation);
- silica gel maintenance: $500 per circuit breaker (two yearly); and
- pressure inspection costs: $300 per circuit breaker (three yearly).

In addition, the average historic repair cost for a failure or defect associated with a Reyrolle type 110/OS/10 circuit breaker is $4 730.

This project excludes the replacement of circuit breakers B552 and C552 at Burnie Substation. Circuit breaker B552 will be replaced and circuit breaker C552 will be decommissioned as part of the Burnie Substation Network Transformer T2 Replacement project that is currently being implemented.

**Sprecher and Schuh type HPFw-311-L circuit breakers**

There are three Sprecher and Schuh type HPFw-311-L circuit breakers installed at Burnie Substation. The Sprecher and Schuh 110 kV Circuit Breaker Condition Assessment Report (TNM-CR-809-0742) assesses the condition of Sprecher and Schuh type HPF 110 kV circuit breakers and recommends that the units at Burnie Substation be replaced. The circuit breaker condition assessment has been based on key asset management considerations, including technical, design, reliability, condition, maintenance, spares and contingency planning, life-cycle and environment issues. The report has identified that Sprecher and Schuh type HPF circuit breakers:

- are the most unreliable 110 kV circuit breakers in the transmission network;
- have a number of inherent technical and major design deficiencies that have the potential to impact adversely on transmission circuit reliability and availability;
- are in poor physical condition;
- are maintenance intensive and costly to maintain when compared with modern equivalent units;
- are no longer supported by the manufacturer's agent; and
- have reached the end of their useful service lives.

The preventive maintenance costs associated with the 110 kV circuit breakers include:

- circuit breaker maintenance: $3 500 per circuit breaker (six yearly); and
- visual inspection costs: $340 per circuit breaker operation (approximately $5 100 per circuit breaker per year based on an average of 15 operations per year).

In addition, the average historic repair cost for a failure or defect associated with a Sprecher and Schuh type HPF 110 kV circuit breaker is $4 500.

The AER has accepted the need to replace this type of circuit breaker in its draft decision. Further information on the circuit breaker population can also be found in the Extra High Voltage Circuit Breaker Asset Management Plan (TNM-PL-809-0541).

## 4.2 CURRENT TRANSFORMERS

The 110 kV current transformers installed at Burnie Station comprise the following types:

- Asea IMBA120 - 21 units (average age of 49 years);
- Asea Brown Boveri 236080 – 3 units (23 years);
- Endurance Electric HS – 6 units (39 years); and
- Endurance Electric IC-115 – 3 units (48 years).

Transend's Current Transformer Asset Management Plan (TNM-PL-809-0615) identifies that Asea IMBA120 and Endurance Electric IC-115 units at Burnie Substation have exceeded their useful service lives and should be decommissioned in conjunction with planned capital works. The units present an increased risk of explosive failure given their age and likely deteriorated condition.

Transend's current strategy is to utilise dead tank circuit breakers with integral current transformers in its circuit breaker replacement program, which will result in the decommissioning of 110 kV post-type current transformers at Burnie Substation. Post-type current transformers installed at Burnie Substation are included in the current transformer decommissioning program, which is detailed in the Current Transformer Asset Management Plan.

Asea Brown Boveri 236080 current transformers will be assessed for their suitability for re-use elsewhere in the transmission network.

The average preventive maintenance costs associated with 110 kV current transformers at Burnie Substation is $1 250 per three phase set.

## 4.3 VOLTAGE TRANSFORMERS

This project includes the installation of voltage transformers on each of the 110 kV transmission lines that connect to Burnie Substation 110 kV to improve the reliability of electricity supply and to reduce the complexity of the associated transmission line protection schemes. Further details of the line voltage transformer installation program and the units that will be installed at Burnie Substation 110 kV are provided in the Voltage Transformer Asset Management Plan (TNM-PL-809-00614).

## 4.4 PROTECTION AND CONTROL

The protection relays designated to be replaced as part of this project are either electromechanical or static types, with the exception of one current differential relay on the Burnie–Emu Bay 110 kV transmission line. The EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) details the need to progressively replace obsolete electromechanical or static protection and control devices to sustain the reliability of the transmission network.

The relays associated with 110 kV equipment at Burnie Substation:

- are obsolete technology;
- are no longer supported by their manufacturer;
- do not have self-diagnostic features; and
- require testing and maintenance on a more frequent basis than modern equivalent assets.

**Burnie–Emu Bay 110 kV transmission line protection**

The transmission line protection on the Emu Bay 110 kV transmission line comprises an electromechanical Compagne Des Compteurs type RXAP distance protection relay and a Siemens type 7SD511 current comparison relay. The RXAP relay was installed in 1968. There are six relays of this type currently in service, and of these, three have failed over the past four years. The EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) specifically recommends that the RXAP relays be replaced due to their poor reliability, slow clearance times and the ongoing need for maintenance and repair. The 7SD511 relay was installed in 1999. There are 42 relays of this type currently in service and of these, 4 have failed over the past 4 years. This relay will be retained as a spare to support the other relays of this type remaining in service.

**Burnie–Hampshire 110 kV transmission line protection**

The transmission line protection on the Burnie–Hampshire 110 kV transmission line comprises two static distance protection relays, a GEC Alstom type PYTS and a Schlumberger type PDS2000B, both installed in 1977. There are seven PYTS relays currently in service and of these, three have failed over the past four years. Routine testing of the PDS2000B relays has identified that they are deviating from there expected characteristic due to ageing components.

The EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) recommends that static relays be progressively replaced due to their poor reliability, tendency for characteristic drift and the ongoing need for maintenance and repair.

**Burnie–Sheffield No.2 110 kV transmission line protection**

The transmission line protection on the Sheffield–Burnie 110 kV transmission line comprises two static distance protection relays, a GEC Alstom type PYTS and a Schlumberger type PDS2000B, both installed in 1977. There are seven PYTS relays currently in service and of these, three have failed over the past four years. Routine testing of the PDS2000B relays has identified that they are deviating from there expected characteristic due to ageing components.

The EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) recommends that static relays be progressively replaced due to their poor reliability, tendency for characteristic drift and the ongoing need for maintenance and repair.

The existing protection and control panel installations also have exposed terminals, are susceptible to dust and moisture ingress and are readily accessible to vermin, presenting an increased risk of failure of secondary system components and interruption to electricity supply. Modern protection schemes have self-diagnostic features, reducing the maintenance liability and enhancing asset reliability and availability.

The issues pertaining to substation protection and control are discussed in EHV Transmission Line Protection Asset Management Plan (TNM-PL-809-0701).

# 5 CUSTOMER CONSULTATION

Transend will liaise directly with relevant stakeholders regarding the intent, scope and implementation of the project as part of the project initiation process.

# 6 BENEFITS

The direct benefits that are achieved through completing the work outlined in the scope of this project are:

- it will contribute to the achievement of the capital expenditure objectives identified in the Rules;
- provision of a safe, secure and reliable electricity supply to customers connected to Burnie Substation by replacing obsolete, unreliable assets that are in poor condition;
- life-cycle cost savings due to reduced operations and maintenance requirements;
- reduced burden on spare parts management by using standard equipment; and
- alignment with strategic asset management plans.

# 7 OPTIONS ANALYSIS

The following options have been considered for the redevelopment of Burnie Substation:

1. maintain existing assets and defer replacement;
2. replace selected assets in-situ;
3. replace selected assets in new switch bays; and
4. completely redevelop Burnie Substation 110 kV.

Other options considered at a high-level, but discounted for the reasons mentioned include:

- **greenfield development** – this option was clearly not a cost-effective alternative as other solutions can be implemented within the existing perimeter of Palmerston Substation at a substantially lower cost.
- **reconfigure and rationalise the existing 110 kV switchyard –** there are no cost-effective alternatives to reconfigure or rationalise Palmerston Substation 110 kV.

## 7.1 OPTION 1 - MAINTAIN EXISTING ASSETS AND DEFER REPLACEMENT

### 7.1.1 SCOPE

The scope for this option includes:

- replacement of assets that present a safety risk, including selected 110 kV current transformers (eight three-phase sets) in 2014;
- continue existing maintenance practices, albeit accelerated due to the declining condition and ageing of assets;
- repairs and corrective maintenance as required; and
- deferred replacement for up to five years.

The capital cost of this option includes an initial $3.36 million ($June 2007) to address safety issues followed by a deferred capital cost of $4.01 million ($June 2007) to replace remaining 110 kV assets five years later.

### 7.1.2 BENEFITS

The benefits for this option are the deferral of capital expenditure and that the identified safety issues are addressed.

### 7.1.3 DRAWBACKS

The drawbacks for this option are that it would:

- not allow Transend to achieve the capital expenditure objectives;
- not satisfactorily address the performance issues identified in section 4 of this document;
- not be sustainable given the demonstrated reliability issues associated with the 110 kV primary and secondary assets;
- result in an increased number of loss of electricity supply events at Burnie Substation when compared with other options;
- incur significantly longer and more frequent outages due to the intensive maintenance regimes that would be required to sustain the existing assets in service (whilst recognising that this approach is almost certainly unlikely to be successful);
- incur increased ongoing operating expenditure due to increased maintenance, condition monitoring and corrective maintenance requirements;
- not align with Transend's policy to utilise dead tank circuit breakers when replacing 110 kV live tank current transformers and circuit breakers; and
- not align with the recommendations made in respective asset management plans for the primary and secondary assets.

#### 7.1.4 Conclusion

Although this option has lower initial capital cost, it is not the preferred option because it does not ensure the reliable operation of Burnie Substation 110 kV.

## 7.2 OPTION 2 - REPLACE SELECTED ASSETS IN-SITU

#### 7.2.1 Scope

The scope for this option includes the replacement of the following assets in 2014:

- replacement of assets that are known to present a significant safety risk, in particular the current transformers;
- replacement of the existing live tank circuit breakers with dead tank units that have integral current transformers;
- replacement of the identified protection and control schemes; and
- implementation of revised maintenance practices.

The capital cost of this option is $6.42 million ($June 2007).

#### 7.2.2 Benefits

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;
- addresses the safety and performance issues associated with the 110 kV assets as identified in section 4 of this document;
- reduces the maintenance requirements and costs associated with the site.

#### 7.2.3 Drawbacks

The option has the following drawbacks:

- higher capital cost than option 1.

#### 7.2.4 Conclusion

This option is technically viable.

## 7.3 OPTION 3 - STAGED REPLACEMENT OF SELECTED ASSETS IN-SITU

### 7.3.1 SCOPE

The scope for this option is essentially the same as Option 2, but implemented using a staged approach based on transmission circuit criticality. This option includes:

- initial replacement of the following assets:
  - Sprecher and Schuh Type HPF 110 kV circuit breakers and associated assets (three bays);
  - other assets that have an assigned transmission circuit criticality rating of four or five (five bays); and
  - other assets that present a safety risk, including selected 110 kV current transformers (two three-phase sets); and
- defer replacement of remaining 110 kV assets by up to three years (two bays).

The capital cost of this option includes an initial $5.88 million ($June 2007) to replace critical assets and to address safety issues followed by a deferred capital cost of $0.85 million ($June 2007) to replace remaining 110 kV assets three years later.

### 7.3.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives in the mid-term;
- addresses the safety issues associated with the 110 kV assets identified in section 4 of this document, in particular the 110 kV current transformers;
- defers capital expenditure associated with lower criticality assets for up to 3 years;
- addresses the performance issues identified in section 4 of this document, with the exception of those transmission circuits that have a criticality less than four; and
- reduces the ongoing maintenance requirements and costs associated with the site.

### 7.3.3 DRAWBACKS

The drawbacks for this option are that it:

- results in a higher initial capital cost than option 1;
- results in a higher overall capital cost than option 2, primarily due to contractor remobilisation and increased internal costs;
- does not align with Transend's policy to utilise dead tank circuit breakers when replacing 110 kV live tank current transformers and circuit breakers for two 110 kV bays;
- reduced efficiencies in project delivery, in particular co-ordination of works associated with the Avoca Substation transformer T2 installation project and asset replacement works; and
- will need additional transmission circuit outages to undertake the works.

### 7.3.4 CONCLUSION

This option is technically viable.

## 7.4 OPTION 4 - REPLACE SELECTED ASSETS IN NEW SWITCH BAYS

### 7.4.1 SCOPE

The scope for this option includes:

- replacement of the existing live tank circuit breakers with dead tank units that have integral current transformers. The implementation methodology for this option includes constructing new transmission circuit bays and relocating existing bays sequentially to new bays in order to minimise outage durations. It involves the following key stages:
  - developing two new switchgear bays and one new bus-coupler bay;
  - restringing the last span of the five transmission circuits into the adjacent bays; and
  - extending the 110 kV bus bars to facilitate the installation of the bus coupler.

- replacement of protection and control schemes; and
- implement revised maintenance practices.

The capital cost of this option is $7.62 million ($June 2007).

#### 7.4.2 Benefits

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;
- addresses the safety issues associated with the 110 kV assets identified in section 4 of this document;
- addresses the performance issues identified in section 4 of this document;
- minimises transmission circuit outage duration during implementation and cutover; and
- reduces the ongoing maintenance requirements and costs associated with the site.

#### 7.4.3 Drawbacks

The drawbacks for this option are that it:

- results in a higher initial capital cost than options 1 and 2;
- requires re-configuration of the 110 kV switchyard;
- requires re-arrangement of transmission line incoming spans; and
- requires the installation of new disconnectors and bus work.

#### 7.4.4 Conclusion

This option is technically viable.

### 7.5 OPTION 5 - COMPLETE REDEVELOPMENT OF BURNIE SUBSTATION 110 KV

#### 7.5.1 Scope

The scope for this option includes:

- in-situ replacement of the existing live tank circuit breakers with dead tank units that have integral current transformers;
- replacement of 110 kV disconnectors in situ;
- replacement of gantry structures;
- replacement of protection and control schemes; and
- implement revised maintenance practices.

The capital cost of this option is $8.10 million ($June 2007).

#### 7.5.2 Benefits

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;
- addresses safety issues associated with the 110 kV assets identified in section 4 of this document, in particular the 110 kV current transformers;
- addresses other performance, reliability and design issues identified in section 4 of this document;
- improves operational functionality as new 110 kV disconnectors would be motorised and capable of remote operation; and
- reduces the ongoing maintenance requirements and costs associated with the site.

#### 7.5.3 Drawbacks

The drawbacks for this option are that it:

- would need outages of an extended duration for each transmission circuit because it would be required to replace 110 kV disconnectors and other infrastructure; and
- would require a higher capital cost than other options

### 7.5.4 CONCLUSION

This option is technically viable.

# 8 OPTION ESTIMATES

A comparison of the net present value of options is provided in Table 1.

**Table 1 - Comparison of options considered**

| Option | | Net present value of costs ($M June 2007) |
|---|---|---|
| 1 | Manage existing assets | -$4.01 |
| 2 | Replace selected assets in-situ | -$4.00 |
| 3 | Staged replacement of selected assets in-situ | -$4.02 |
| 4 | Replace selected assets in new switch bays | -$4.57 |
| 5 | Complete redevelopment of Burnie Substation 110 kV | -$4.79 |

The economic analysis includes the cost impact to customers in the event of a major circuit breaker failure using a probabilistic approach based on current and forecast load data for each individual transmission circuit connected to Burnie Substation 110 kV.

# 9 PREFERRED OPTION

Option 2 (replacement of selected assets in-situ) is the preferred option because it is the most cost effective solution to address the identified safety and performance issues presented by the assets at Burnie Substation 110 kV. This approach will also minimise the number and duration of transmission circuit outages due to reduced frequency and duration of maintenance.

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | CREEK ROAD SUBSTATION 110 KV REDEVELOPMENT |
| **TRIM REFERENCE** | D09/3452 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 2.0 |
| **TRANSEND CONTACT** | DAVID KRUIJVER |
| **PROJECT NUMBER** | ND0733 |

## ATTACHMENT A4

# CONTENTS

# 1 BACKGROUND

Creek Road Substation is critical to ensuring a secure and reliable electricity supply to southern Tasmania. It is an integral part of the transmission network in southern Tasmania with 110 kV connections to Chapel Street, New Norfolk and Risdon substations. It also connects North Hobart Substation to the transmission network via two 110 kV underground cables and Aurora Energy's zone substations in the greater Hobart area at 33 kV. Both North Hobart Substation and Aurora Energy's zone substations supply Hobart's central business district (CBD), including hospitals and other critical facilities. The load connected to Creek Road and North Hobart substations (excluding load transferred to other parts of the 110 kV transmission network) is approximately 180 MVA.

Creek Road Substation was originally commissioned in 1916 as Hobart Substation and operated at a primary voltage of 88 kV. It was the first major substation to supply electricity to Hobart and surrounding areas. The substation was redeveloped in 1951 to operate at a voltage of 110 kV and was configured as a ring bus arrangement. The substation was renamed Creek Road Substation at that time.

In 1999, Transend engaged Ascension Consulting and APC-Worley consultants to provide an independent appraisal of the ability of the 110 kV and 22 kV assets at Creek Road Substation to maintain a secure and reliable electricity supply over a 15 year period. That independent report identified that a substantial proportion of the assets at Creek Road Substation are aged and in poor condition and recommended that the substation be redeveloped. Transend has adopted a staged approach with the redevelopment of Creek Road Substation.

In 2002, Transend replaced a number of 110 kV voltage transformers that were in extremely poor condition and were likely to fail explosively.

Also in 2002, Transend implemented the Creek Road Substation 33 kV development project. This project was part of the Hobart Area Supply Upgrade (HASU) program, a joint strategy with Aurora Energy to improve the security and reliability of electricity supply to the greater Hobart area. The Creek Road Substation 33 kV development project included the installation of a new 33 kV indoor switchboard and the replacement of the 110/22 kV supply transformers T2, T3 and T4 and associated protection at Creek Road Substation. As part of that project, the 22 kV switchgear was progressively decommissioned.

# 2 PROJECT OVERVIEW

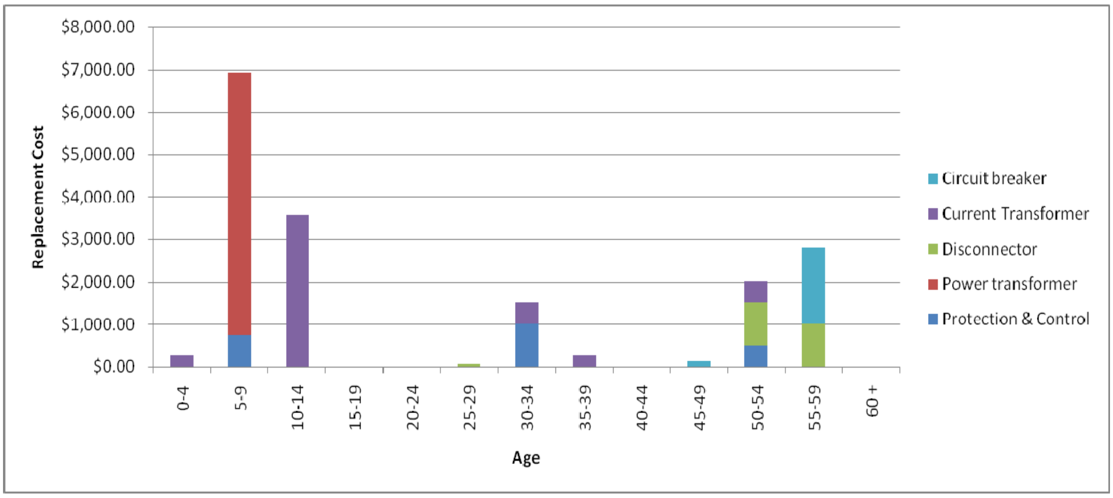
The planned redevelopment of Creek Road Substation 110 kV comprises the replacement of the vast majority of the primary and secondary equipment in a revised configuration. This project includes the following major works at Creek Road Substation:

- replacement of 16 Reyrolle type 110/OS/10 circuit breakers;
- replacement of 29 disconnectors;
- replacement of seven three phase sets of voltage transformers (note that six sets may be re-used elsewhere in the transmission network);
- replacement of 20 sets of three phase post type current transformers (note that 15 sets may be re-used elsewhere in the transmission network);
- replacement of 309 multi-piece post insulators;
- replacement of the 110 kV transmission line protection schemes; and
- Replacement of the bus bar protection scheme.

Figure 1 presents a summary of the age of the key 110 kV assets (by category) at Creek Road Substation by asset replacement cost (note that the scope of this project does not include replacement of the power transformers or selected protection and control systems). Figure 1 clearly illustrates that the vast majority of the assets included in the Creek Road Substation 110 kV redevelopment project are well beyond their nominal service lives of 45 years for primary assets and 15 years for secondary assets as defined by Sinclair Knight Merz in its 'Assessment of Economic Lives for Transend Regulatory Asset Classes' report prepared in April 2008 provided as attachment 24 of Transend's revenue proposal. A large proportion of the primary assets at Creek Road Substation will be at least 63 years old when decommissioned.

**Figure 1 – Summary of age and value ($000) of major 110 kV assets installed at Creek Road Substation**




# 3 PROJECT TIMING

The Creek Road Substation 110 kV redevelopment project was originally scheduled to be completed in 2008–09. The project has been deferred because of the need to coordinate the project with the Hobart Area Supply Upgrade program and the Southern Power System Security program. These programs have been attributed a higher priority because of the immediate need to increase the capacity of the transmission and distribution systems in southern Tasmania.

Progressing the Creek Road Substation redevelopment project as per the original schedule would have increased the risk of supply to Hobart's CBD if undertaken in parallel with the above-mentioned programs of work. It would also have been inefficient due to sequencing implications and re-work required. Interim risk mitigation measures have been put in place to enable this project to be deferred until the final stage of the Southern Power System Security program (the Waddamana–Lindisfarne 220 kV transmission line project) is completed. The Hobart Area Supply Upgrade program has been completed in the current regulatory control period. The Creek Road Substation 110 kV redevelopment project is scheduled to commence in 2012 and be completed in 2014.

The Creek Road Substation 110 kV redevelopment project is currently the highest ranking of all proposed projects in Transend's works prioritisation tool, primarily because of its importance within the transmission network and the criticality of the load connected to the substation.

It is possible that further works may need to be implemented prior to the planned commencement of the project because of the deteriorated condition of certain assets and the fact that additional asset condition issues will most likely be identified prior to commencement of the project.

# 4 INVESTMENT NEED

## 4.1 SUMMARY

This project is required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the National Electricity Rules (Rules):

- comply with all applicable regulatory obligations associated with the provision of prescribed transmission services;
- maintain the quality, reliability and security of supply of prescribed transmission services; and
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

The key investment drivers for this project are to address identified safety, condition, and performance issues presented by the primary and secondary assets at Creek Road Substation 110 kV.

## 4.2 CIRCUIT BREAKERS

The 110 kV circuit breakers (16 units) installed at Creek Road Substation are Reyrolle type 110/OS/10 units and are among the oldest of the fleet. The Reyrolle Type OS/10 110 kV Circuit Breaker Condition Assessment Report (TNM-CR-806-0772) assesses the condition of Reyrolle type OS/10 circuit breakers and recommends that the units at Creek Road Substation be replaced. The circuit breaker condition assessment has been based on key asset management considerations, including technical, design, reliability, condition, maintenance, spares and contingency planning, life-cycle and environmental issues. The condition assessment report provides details of 18 failures and defects associated with 110 kV circuit breakers installed at Creek Road Substation since 1998. This poor level of performance indicates that these circuit breakers are in poor condition and that the level of performance of the units is likely to deteriorate further over time. The condition assessment report has identified that Reyrolle type 110/OS circuit breakers:

- have a number of inherent technical and design deficiencies that have adversely impacted transmission circuit reliability and availability;
- are unreliable, in particular the air and insulating oil systems;
- are maintenance intensive and costly to maintain when compared with modern equivalent units;
- spare parts are no longer available from the manufacturer’s agent;
- require skilled personnel to maintain - the availability of specialised maintenance resources is declining; and
- have reached the end of their useful service lives.

All other transmission companies in Australia and New Zealand have already replaced their population of Reyrolle type 110/OS/10 circuit breakers for the same reasons outlined above. Transend’s reasons for replacing this type of circuit breaker are no different to those of other industry participants.

The preventive maintenance costs associated with the 110 kV circuit breakers include:

- circuit breaker maintenance: $7,500 per circuit breaker (six yearly);
- insulating oil costs: $4,200 per circuit breaker (six yearly);
- compressor maintenance: $1,000 per compressor (six-monthly for the two compressors at Creek Road Substation);
- silica gel maintenance: $500 per circuit breaker (two yearly); and
- pressure inspection costs: $300 per circuit breaker (three yearly).

In addition, the average historic repair cost for a failure or defect associated with a Reyrolle type 110/OS circuit breaker is $4,730.

Further information on the circuit breaker population can also be found in the Extra High Voltage Circuit Breaker Asset Management Plan (TNM-PL-809-0541).

## 4.3 DISCONNECTORS

The 110 kV disconnectors installed at Creek Road Substation comprise the following types:

- Acelec type HDB5L - six units (average age of 50 years);
- Essantee type 05552 - seven units (average age of 58 years);
- Stanger type TTT - 16 units (average age of 55 years); and
- Taplin type D751 - one unit; (average age of 26 years).

The average maintenance costs associated with the 110 kV disconnectors are $3,000 per disconnector.

Details of each disconnector type can also be found in the Extra High Voltage Disconnector and Earth Switch Asset Management Plan (TNM-PL-809-0606).

### 4.3.1 ACELEC TYPE HDB5L

The Acelec disconnectors are in poor condition and are susceptible to thermal failure of the conductive braids. This type of disconnector is difficult to maintain due to a complex fixed contact arrangement. In addition, a number of disconnectors are mounted on girders and/or underhung approximately 10 metres above ground level, requiring additional resources to maintain.

Any spares required to sustain this type of disconnector in service need to be locally manufactured or salvaged from decommissioned units.

The current rating of the type HDB5L disconnectors is 800 Amps, resulting in disconnectors D129, E129 and K129 at Creek Road Substation being circuit limiting equipment, however this limitation currently does not constrain the associated transmission circuits.

### 4.3.2 ESSANTEE TYPE 05552

The Essantee disconnectors are in very poor condition and need to be replaced. The units are susceptible to thermal failure of the conductive braids. The disconnectors have also experienced failures of the operating linkage, preventing the disconnector from operating; seizing of pivot joints, preventing contacts and disconnector from closing; and contact misalignment due to weakened springs and worn pivot joint assemblies.

The Essantee disconnectors are designed for operation at 88 kV and do not provide the required electrical clearances for compliant operation at 110 kV.

### 4.3.3 STANGER TYPE TTT

The Stanger disconnectors are in poor condition and need to be replaced. The units are an obsolete design, do not have available spare parts and have exceeded their assigned service life.

### 4.3.4 TAPLIN TYPE D751

The Taplin disconnector A429 at Creek Road Substation is in acceptable condition. However, the unit is mounted on a girder approximately 10 metres above ground level and requires additional resource effort to maintain. The unit will be retained for spares.

## 4.4 VOLTAGE TRANSFORMERS

The 110 kV voltage transformers installed at Creek Road Substation comprises the following types:

- Balteau type UEV110 - three units (average age of 29 years); and
- Trench type 123/3 units - 18 units (average age of 9 years).

In 2000, a number of 110 kV voltage transformers (Brown Boveri TMZF and Asea Type EMFA) that were in extremely poor condition were replaced to eliminate the likelihood of explosive failure and to sustain the performance of the substation prior to the redevelopment of Creek Road Substation 110 kV. The replacement units were manufactured by Trench and are in acceptable condition. The units will be assessed for their suitability for redeployment elsewhere in the transmission network following their decommissioning as part of the redevelopment project.

The Balteau 110 kV voltage transformers are of an obsolete design and are in poor electrical condition. They have high percentage power factor readings, which indicate excessive moisture in the insulating oil and likely degradation of the winding insulation. While Transend has not experienced any major failures of Balteau voltage transformers, other Australian transmission companies have reported explosive failures of Balteau voltage transformers of a similar design. The explosive failure of a voltage transformer presents a major safety risk to employees and contractors working in the vicinity of the voltage transformer at the time of failure.

The Voltage Transformer Asset Management Plan (TNM-PL-809-00614) recommends that the units should be progressively replaced over the next five years.

The average maintenance costs associated with 110 kV voltage transformers at Creek Road Substation is $1,250 per three phase set.

## 4.5 CURRENT TRANSFORMERS

In 1996, a number of Reyrolle 110 kV current transformers that were contaminated with polychlorinated biphenyl (PCB) and in poor condition were replaced to ensure compliance with environmental legislation and to sustain the performance of the substation. The in-service current transformers at Creek Road Substation include:

- ABB 236080 - 45 units (average age 13 years);
- Modern Products Drg. 039931 - six units (average age 34 years); and
- Reyrolle Drg. 015204 - nine units (average age 52 years).

The Reyolle units are in poor condition (high power factor) and utilise a silica gel breather that requires additional maintenance. The Current Transformer Asset Management Plan (TNM-PL-809-0605) recommends that the Reyrolle voltage transformers be replaced.

The ABB units will be assessed for their suitability for redeployment elsewhere in the transmission network following their decommissioning as part of the redevelopment project. The Modern Products units will be retained as spares.

The average maintenance costs associated with 110 kV current transformers at Creek Road Substation is $5,500 per three phase set.

## 4.6 POWER CABLES

A 70 metre nitrogen-filled 110 kV power cable connects the Chapel Street–Creek Road No. 2 110 kV transmission line to its switching bay at Creek Road Substation. The cable was manufactured by Glover and Co. in 1959 and is single core, gas-insulated design comprising copper conductor, paper insulation and an aluminium sheath. The cable is susceptible to gas leaks and subsequent loss of gas pressure. Despite numerous attempts to address the issue, the cable continues to leak nitrogen gas. The Power Cables Asset Management Plan (TNM-PL-809-0602) recommends that the Chapel Street–Creek Road No. 2 110 kV power cable at Creek Road Substation be replaced in conjunction with other planned capital works.

## 4.7 POST INSULATORS

The 110 kV post insulators installed at Creek Road Substation comprise:

- P1141 - 48 units;
- P640 units - 159 units; and
- P701A - 102 units.

The post insulators are a multi-piece construction that comprise individual insulators bolted together to achieve the required voltage rating. The multi-piece design post insulators are susceptible to mechanical failure in certain operating environments due to moisture freezing within the post insulator, causing the porcelain components to crack. Transend has experienced a significant number of mechanical and electrical failures of EHV multi-piece post insulators over the past 10 years. The consequences of failure have included an increased safety risk to personnel working in switchyards, considerable disruption to electricity supply and the requirement for unplanned outages to facilitate replacement of post insulators.

The Post Insulator Asset Management Plan (TNM-PL-809-0614) recommends the progressive replacement of multi-piece post insulators.

## 4.8 BUS CONDUCTOR AND FITTINGS

The 110 kV bus conductors at Creek Road Substation are constructed from twin 19/.092 hard drawn stranded copper conductor and 32 mm x 10 gauge copper bar, which is not a standard size and requires custom fittings. In addition, the bus bar conductors and fittings are not sufficiently rated.

The 110 kV conductor fittings utilise bolted type fittings throughout the switchyard. Bolted terminal clamps are an old technology which have inherent design issues that can result in the loosening of bolts over time. The loosening of the conductor fittings can lead to high resistance joints. Modern practice is to use compression type fittings that mitigates the risks associated with bolted fittings.

## 4.9 PROTECTION AND CONTROL SYSTEMS

The vast majority of the protection and control devices that will be replaced as part the Creek Road Substation 110 kV redevelopment project are either electromechanical or static types. The EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) and the EHV bus bar Protection Asset Management Plan (TNM-PL-809-0702) details the need to progressively replace obsolete electromechanical or static protection and control devices to sustain the reliability of the transmission network because they:

- are unreliable and maintenance intensive;
- are obsolete technology;
- are no longer supported by their manufacturer;
- do not have self-diagnostic features; and
- require testing and maintenance on a more frequent basis than modern equivalent assets.

The average preventive maintenance costs associated with the protection and control systems that are scheduled for replacement at Creek Road Substation include:

- transmission line distance protection schemes: $4,200 per scheme (three yearly); and
- 110 kV bus-zone scheme: $11,050 (three yearly).

The following protection scheme replacements are included in the Creek Road Substation 110 kV redevelopment project.

**Creek Road–North Hobart 110 kV transmission line protection schemes**

The transmission line protection on the Creek Road–North Hobart 110 kV transmission lines each comprise one GEC type YTS static distance protection relay and one electromechanical one GEC DSF7 pilot wire differential relay. Both protection schemes were installed in 1977.

There are 13 YTS relays currently in service in the transmission network, and of these, one has failed over the past five years. These relays are exhibiting signs of characteristic drift. The two GEC DSF7 relays are the only ones installed in the Tasmanian transmission network.

**New Norfolk–Creek Road 110 kV transmission line protection scheme**

The transmission line protection on the New Norfolk–Creek Road 110 kV transmission line comprises two static distance protection relays, a GEC type YTS and a Reyrolle type THS relay.

The YTS relay was installed in 1977. There are 13 YTS relays currently in service in the transmission network, of which one has failed over the past five years. These relays are exhibiting signs of characteristic drift.

The THS relay was installed in 1981. There are 22 relays of this type in service in the transmission network, of which three have failed over the past four years.

**Chapel Street–Creek Road no. 2 and 3 110 kV transmission lines protection schemes**

The transmission line protection on the Chapel Street–Creek Road no. 2 and 3 110 kV transmission lines each comprise a GEC type YTS static distance protection relay and a Siemens 7SD511 microprocessor relay.

The YTS relay was installed in 2007. Issues associated this type of relay are discussed above. The Siemens 7SD511 is a microprocessor based relay that utilises digital differential communications and was installed in 1997. This type of relay has nine recorded defects over the past five years and there are currently 38 relays installed throughout the transmission network.

The Siemens 7SD511 is a microprocessor based relay that utilises digital differential communications and was installed in 1997. This type of relay has 9 recorded defects over the past 5 years and there are currently 38 installed around the state with 8 spares that have been used in previous installations. These relays will be retained as spares.

**Chapel Street–Creek Road–Risdon 110 kV transmission line protection scheme**

The transmission line protection on the Chapel Street–Creek Road–Risdon 110 kV transmission line comprises a GEC type YTS static distance protection relay and an Areva P543 microprocessor relay.

The YTS relay was installed in 2007. Issues associated this type of relay are discussed above. The Areva P543 relay was temporarily installed in 2006 as part of a transmission line configuration and augmentation project. This relay will be re-installed elsewhere in the transmission network or retained as spares.

**110 kV bus bar protection**

The 110kV bus bar protection installed at Creek Road Substation is a GEC MBCZ low impedance scheme of a static design that was installed in 1996. This type of scheme has 17 recorded failures over the past five years and there are currently nine schemes of this type installed throughout the transmission network. Spares are no longer available for this type of bus bar protection. This type of bus bar protection is not suitable for the revised bus bar configuration and as such will be retained for spare parts.

### 4.10 NETWORK DEVELOPMENT CONSIDERATIONS

The 110 kV switchyard at Creek Road Substation is configured as a ring bus arrangement. This arrangement presents reliability and operational issues, including:

- all transmission circuits and loads are connected to single points on the 110 kV bus bar;
- reduced operational flexibility. Removal of critical plant from service for maintenance purposes requires extensive planning and transmission network reconfiguration. Loads cannot be transferred to different points on the bus bar, which constrains plant outages times to summer months (as plant not being maintained is also required to be out of service). and
- the ring bus arrangement does not readily facilitate extension for future development projects.

Redevelopment of Creek Road Substation 110 kV will enable reconfiguration of the switchyard arrangement to provide improved reliability and operational flexibility. Each transmission circuit and load will have the ability to connect to multiple points on the 110 kV bus bar, which will enable all major items of plant to be maintained with minimal reduction in security of electricity supply.

In 2006, the 110 kV transmission lines between Chapel Street and Risdon substations were augmented to provide additional capacity to southern Tasmania. The 110 kV transmission network at Creek Road Substation was reconfigured by removing one 110 kV transmission line connection (and creating a normally-open teed arrangement) to Creek Road Substation to avoid the need to augment the 110 kV bus bars at Creek Road Substation. This reconfiguration reduced the security of electricity supply to Creek Substation, albeit whilst providing other benefits. The redevelopment of Creek Road Substation 110 kV provides the opportunity to install 110 kV bus bars of adequate capacity to optimally configure the 110 kV transmission network in the vicinity of Creek Road Substation, thereby improving the security of electricity supply to Creek Road Substation.

# 5 CUSTOMER CONSULTATION

Transend intends to liaise directly with relevant stakeholders regarding the intent, scope and implementation of the project. The proposed redevelopment project has been highlighted on a number of occasions during Transend’s Annual Planning Review process.

# 6 BENEFITS

The direct benefits of redeveloping Creek Road Substation 110 kV include:

- contributing to the achievement of the capital expenditure objectives identified in the Rules;
- provision of a safe, secure and reliable electricity supply to customers connected to Creek Road Substation, in particular Hobart's CBD by replacing obsolete, unreliable assets that are in poor condition;
- life-cycle cost savings due to reduced operations and maintenance requirements;
- reduced burden on spare parts management by using standard equipment; and
- alignment with strategic asset management plans.

# 7 OPTIONS ANALYSIS

The following options have been considered for the redevelopment of Creek Road Substation:

1. manage existing assets and defer replacement;
2. replace assets in situ;
3. staged replacement of assets in situ over three years;
4. redevelop using air insulated switchgear;
5. redevelop using gas insulated switchgear; and
6. redevelop using hybrid switchgear.

Other options considered at a high-level, but discounted for the reasons mentioned:

- **Off-site greenfield redevelopment -** not considered to be a cost effective alternative as other solutions can be implemented within the existing perimeter of Creek Road Substation at a lower cost. This option has advantages over other options in terms of outage requirements, however the additional costs associated with purchasing new land and easement for deviation of transmission circuits outweigh the benefits of reduced outages.
- **Replace selected assets only** - replacement of selected assets has already been undertaken in order to defer major works at Creek Road Substation. The need to replace the large number of assets that present safety, condition and performance issues means that combining the works as part of a major redevelopment is the most cost-effective solution.

## 7.1 OPTION 1 - MANAGE EXISTING ASSETS AND DEFER REPLACEMENT

### 7.1.1 SCOPE

The scope for this option includes:

- continue existing maintenance practices for the majority of assets, albeit accelerated due to the declining condition and aging of the assets;
- replace assets that are known to present a significant safety risk, including voltage transformers, current transformers and post insulators in 2014;
- replace identified disconnectors that do not provide the required electrical clearances for compliant operation at 110 kV in 2014;
- replace the SCADA and bus bar protection scheme in 2014;
- replace the underground 110 kV power cable that is in poor condition in 2014; and

- defer replacement of remaining assets by up to two years.

The capital cost of this option includes an initial $4.86 million ($June 2007) to address the highest priority issues, followed by a deferred capital cost of $22.57 million ($June 2007) to replace the remaining assets two years later.

#### 7.1.2 BENEFITS

The benefit for this option is the deferral of capital expenditure.

#### 7.1.3 DRAWBACKS

The drawbacks for this option are that it:

- does not address the performance, reliability and design issues identified in Section 4;
- incurs increased ongoing operating expenditure due to increased maintenance, condition monitoring requirements and corrective maintenance requirements;
- is not sustainable given the reliability issues associated with the 110 kV assets;
- does not address the operational issues associated with the 110 kV ring bus arrangement;
- incurs the longest, and most frequent outages due to maintenance regimes that are required to maintain the existing assets;
- involves an increased risk of loss of supply events at Creek Road Substation; and
- does not align with the recommendations made in the independent report by Ascension Consulting and APC-Worley. Knowingly operating existing assets with identified performance and condition issues potentially exposes Transend to litigation issues in the event of a supply disruption to Hobart's CBD caused by an asset failure at Creek Road Substation.

#### 7.1.4 CONCLUSION

Although option 1 has the least capital cost option in the short term, it is not the preferred option because it does not ensure the reliable operation of Creek Road Substation.

### 7.2 OPTION 2 - REPLACE ASSETS IN SITU

#### 7.2.1 SCOPE

The scope for this option includes:

- in-situ replacement of the existing live tank circuit breakers with dead tank units with integral current transformers;
- replacement of all 110 kV disconnectors with new motorised units in situ;
- replacement of all bus bars with aluminium conductor and compression fittings;
- replacement of protection and control schemes; and
- implement revised maintenance practices.

This option includes redeveloping the site using the existing ring-bus arrangement.

The capital cost of this option is $27.27 million ($June 2007).

#### 7.2.2 BENEFITS

The benefits for this option are that it:

- addresses most of the asset issues in Section 4; and
- reduces the ongoing maintenance requirements and costs associated with the site.

#### 7.2.3 DRAWBACKS

The option has the following drawbacks:

- high capital cost as the total number of assets replaced is higher than alternative, rationalised arrangements;
- it does not address the operational issues associated with the ring bus arrangement identified in Section 4;
- presents increased risks during implementation working within a constrained, energised site;
- obtaining the required outages to undertake the works will be difficult (in order to allow key equipment to be decommissioned, civil works including concrete curing, and finally erection and commissioning of the new equipment);
- long outages will reduce reliability of supply to customers supplied from Creek Road Substation;
- additional temporary works required during implementation to maintain secure and reliable supply at Creek Road Substation and remote sites; and
- may have implications on future development at the site.

#### 7.2.4 CONCLUSION

This is not the preferred option because it does not address the reliability and performance issues associated with the 110 kV ring bus arrangement at Creek Road Substation. In addition, implementation would be difficult in terms of obtaining the necessary outages to undertake the works.

### 7.3 OPTION 3 - STAGED REPLACEMENT OF SELECTED ASSETS IN-SITU

#### 7.3.1 SCOPE

The scope for this option is essentially the same as option 2, but implemented using a staged approach based on transmission circuit criticality. This option includes:

- initial replacement of assets that have an assigned transmission circuit criticality rating of four or five (13 bays);
- initial replacement of other remaining assets that are known to present a safety risk, including voltage transformers, current transformers and post insulators in 2014;
- replacement of the underground 110 kV power cable that is in poor condition in 2014; and
- deferred replacement of the remaining 110 kV assets by up to three years (three bays).

The capital cost of this option includes an initial $23.20 million ($June 2007) to replace critical assets and to address safety issues followed by a deferred capital cost of $4.22 million ($June 2007) to replace remaining 110 kV assets three years later.

#### 7.3.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives in the mid-term;
- addresses the safety issues associated with the 110 kV assets identified in Section 4 of this document;
- defers capital expenditure associated with lower criticality assets for up to three years;
- addresses the performance issues identified in Section 4 of this document, with the exception of those transmission circuits that have a criticality less than four; and
- reduces the ongoing maintenance requirements and costs associated with the site.

### 7.3.3 DRAWBACKS

The drawbacks for this option are that it:

- results in a higher initial capital cost than option 1;
- results in a higher overall capital cost than option 2, primarily due to contractor remobilisation and increased internal costs;
- does not align with Transend's policy to utilise dead tank circuit breakers when replacing 110 kV live tank current transformers and circuit breakers for two 110 kV bays;
- it does not address the operational issues associated with the ring bus arrangement identified in Section 4;
- reduced efficiencies in project delivery;
- will need additional transmission circuit outages to undertake the works; and
- may have implications on future development at the site

### 7.3.4 CONCLUSION

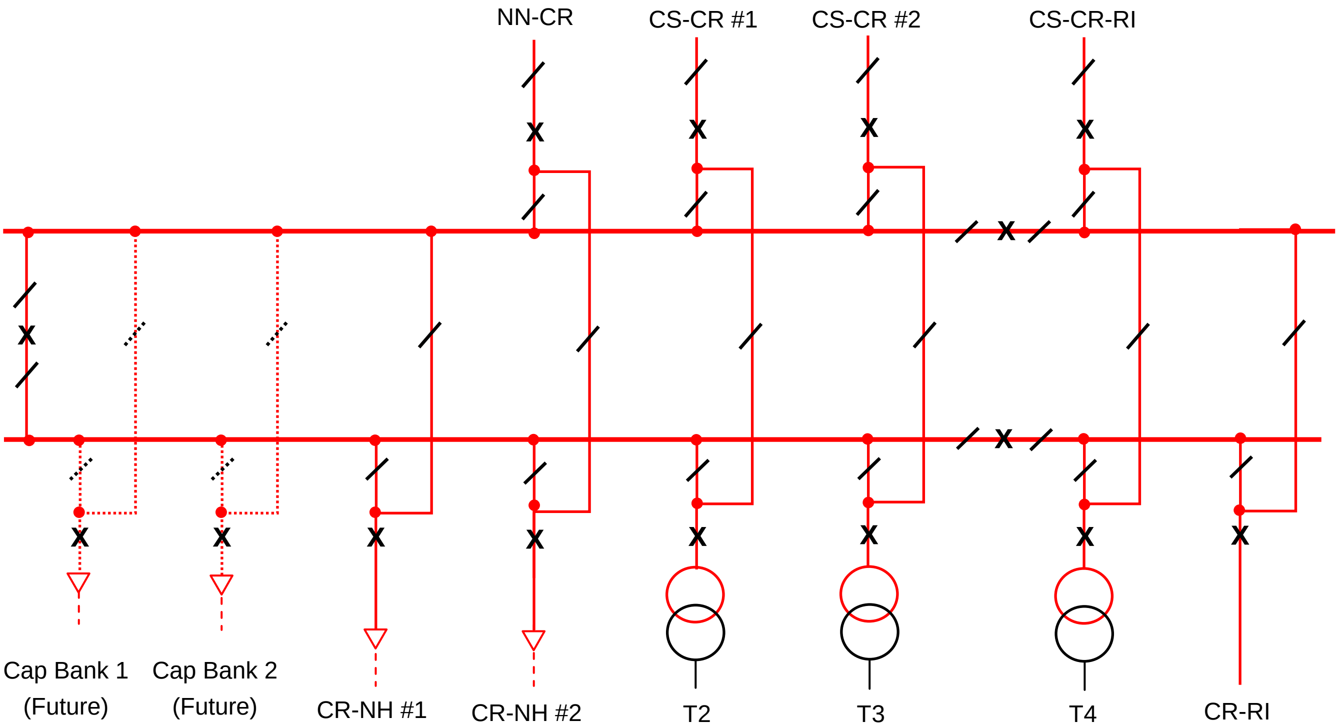
This option is technically viable.

## 7.4 OPTION 4 - REDEVELOP USING AIR INSULATED SWITCHGEAR

### 7.4.1 SCOPE

This option includes the replacement, rationalisation and reconfiguration of 110 kV assets at Creek Road Substation using air-insulated switchgear (AIS). This option includes redeveloping the site using a double bus arrangement as presented in Figure 2.

**Figure 2 – Option 3: single line diagram (AIS)**




This option includes:

- installing new dead tank circuit breakers with integral current transformers;
- installing motorised disconnectors;
- installing tubular aluminium bus bars and compression fittings;
- installing voltage transformers on the transmission lines;
- extending the existing 33 kV control building to include new protection and control equipment;
- disposing of existing switchgear and protection and control equipment; and
- demolishing redundant buildings.

The capital cost of this option is $27.03 million ($June 2007).

### 7.4.2 Benefits

This option has the following benefits:

- it addresses all of the issues in Section 4;
- it reduces the ongoing maintenance requirements and costs associated with the site through:
  - a reduction in number of circuit breakers from 16 to 12;
  - a reduction in the number of disconnectors from 30 to 24;
  - simplification of protection and control schemes;
  - decommissioning all post-type 110 kV current transformers; and
  - rationalisation of infrastructure (post insulators, gantry structures, bus conductors etc.).

- improves the operational flexibility of the site;
- reduces the overall footprint of the site;
- allows for future expansion of the site; and
- allows for rationalisation of auxiliary equipment.

#### 7.4.3 DRAWBACKS

The drawbacks for this option are that the:

- double-bus bar option is difficult to achieve given site constraints and outage management issues;
- additional temporary works required during implementation to maintain secure and reliable supply at Creek Road Substation and remote sites; and
- increased risks presented during implementation work within a constrained site.

#### 7.4.4 CONCLUSION

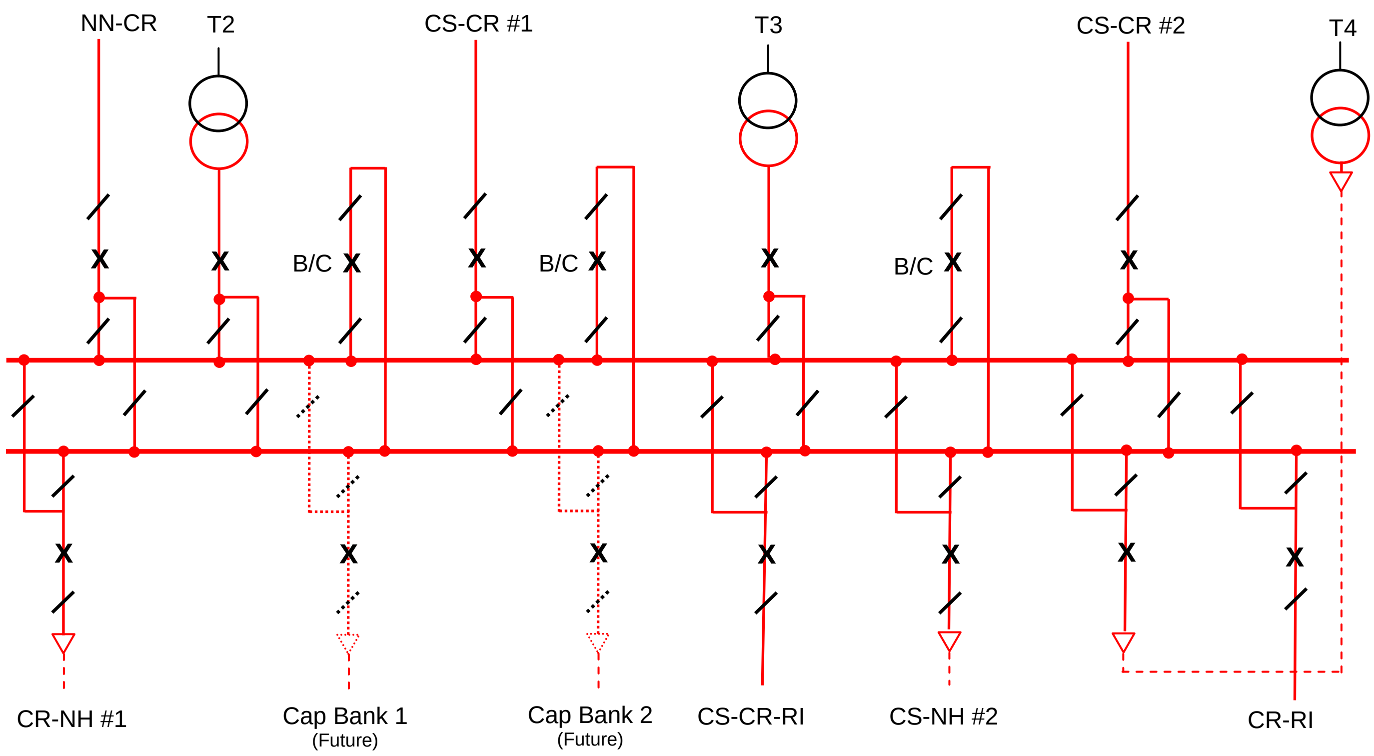
This option is technically viable.

### 7.5 OPTION 5 - REDEVELOP USING GAS INSULATED SWITCHGEAR

#### 7.5.1 SCOPE

This option includes the replacement, rationalisation and reconfiguration of 110 kV assets at Creek Road Substation using gas-insulated switchgear (GIS). This option includes redeveloping the site using a double bus arrangement as presented in Figure 3.

**Figure 3 – Option 4: single line diagram (GIS)**



This option includes:

- installing new 110 kV GIS;
- new protection and control equipment;
- disposing of existing switchgear and protection and control equipment; and
- demolishing redundant buildings.

The capital cost of this option is $26.62 million ($June 2007).

#### 7.5.2 BENEFITS

This option has the following benefits:

- addresses all of the issues in Section 4;
- requires minimal outages for implementation;
- it reduces the ongoing maintenance requirements and costs associated with the site through:
  - a reduction in number of circuit breakers;
  - a reduction in the number of disconnectors;
  - simplification of protection and control schemes;
  - rationalisation of infrastructure (post insulators, gantry structures, bus conductors etc.)
- improves the operational flexibility of the site;
- reduces the overall footprint and visual impact of the site;
- allows for some future expansion of the site; and
- allows for rationalisation of auxiliary equipment.

#### 7.5.3 DRAWBACKS

Drawbacks of this option include:

- future expansion costs may be higher than AIS equivalent.

#### 7.5.4 CONCLUSION

This option is technically viable.

### 7.6 OPTION 6 - REDEVELOP USING HYBRID SWITCHGEAR

#### 7.6.1 SCOPE

This option includes the replacement, rationalisation and reconfiguration of 110 kV assets at Creek Road Substation using hybrid switchgear. This option includes redeveloping the site using a double bus arrangement as presented in option 3.

The scope for is the same as option 3, but includes the use of hybrid switchgear in lieu of AIS.

The capital cost of this option is $26.62 million ($June 2007).

#### 7.6.2 BENEFITS

- This option has similar benefits to option 3.

### 7.6.3 DRAWBACKS

The drawbacks for this option are that:

- it may require longer outages for implementation, depending on the implementation methodology adopted; and
- technology risk as Transend has not previously utilised hybrid switchgear in its transmission network.

### 7.6.4 CONCLUSION

This option is technically viable.

# 8 OPTION ESTIMATES

A comparison of the net present value of options is provided in Table 1.

**Table 1 – Comparison of options considered**

| Option | | Net present value of costs ($M June 2007) |
|---|---|---|
| 1 | Manage existing assets and defer replacement | -12.71 |
| 2 | Replace assets in-situ | -13.63 |
| 3 | Staged replacement of selected assets in-situ | -13.16 |
| 4 | Redevelop using air insulated switchgear | -13.07 |
| 5 | Redevelop using gas insulated switchgear | -12.68 |
| 6 | Redevelop using hybrid switchgear | -12.67 |

The economic analysis includes the cost impact to customers in the event of a major circuit breaker failure using a probabilistic approach based on current and forecast load data for each individual transmission circuit connected to Creek Road Substation.

# 9 PREFERRED OPTION

Given the constraints and numerous construction methodologies that may be implemented, options 3, 4, 5 and 6 are acceptable options.

Transend intends to issue this project as a design and construct package to achieve the best economic outcome. The project documentation will leave it open to tenderers to submit arrangements that may include AIS, GIS or hybrid switchgear solutions. Transend completed a very similar redevelopment project at Risdon Substation. This project was competitively sourced using a ‘design and construct’ contracting framework. The least-cost solution proposed by tenderers was the application of GIS technology.

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | KNIGHTS ROAD SUBSTATION 110 KV REDEVELOPMENT |
| **TRIM REFERENCE** | D09/3549 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 2.0 |
| **TRANSEND CONTACT** | DAVID KRUIJVER |
| **PROJECT NUMBER** | ND0968 |

## ATTACHMENT A5

# CONTENTS

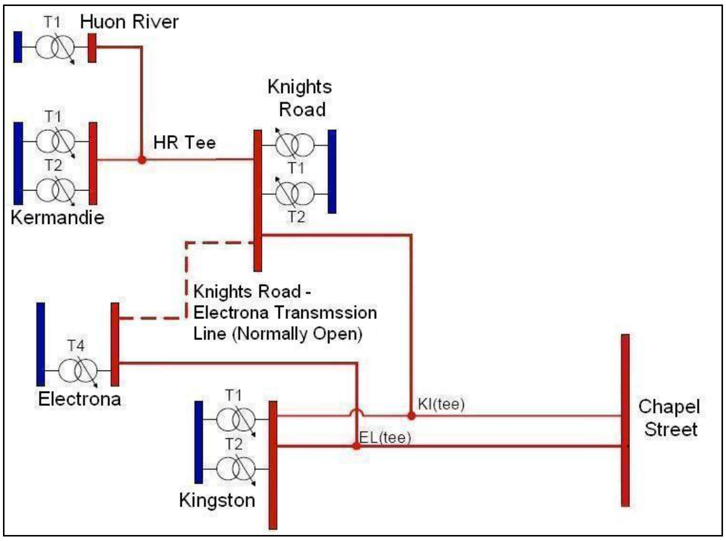
# 1 BACKGROUND

Knights Road Substation is connected to the transmission network via the Chapel Street–Knights Road–Electrona and Knights Road–Electrona 110 kV transmission lines. Knights Road Substation supplies Kermandie and Huon River Substations at 110 kV and Aurora Energy at 11 kV. The combined load at Huon River, Kermandie and Knights Road substations exceeded 25 MW in winter 2008.

The majority of the 110 kV assets in service at Knights Road Substation were installed when the substation was commissioned in 1962. A new 110/11 kV connection site was established at Knights Road Substation in 1987.

Figure 1 presents the schematic diagram of the Huon area transmission network that connects to Knights Road Substation.

**Figure 1 – Huon area transmission network schematic diagram**




# 2 PROJECT OVERVIEW

The works at Knights Road Substation include the replacement of selected 110 kV switch bays and protection and control systems associated with the 110 kV and 11 kV systems. In particular, this project includes the following works:

- replacement of Reyrolle type 110/OS/10 110 kV circuit breakers;
- replacement of Asea type EMFA 120 110 kV voltage transformers;
- installation of 110 kV voltage transformers on each transmission line;
- replacement of girder-mounted disconnectors with pedestal mounted units;
- replacement of multi-piece post insulators;
- replacement of the protection scheme on the Knights Road–Huon River–Kermandie 110 kV transmission line;
- replacement of the 110 kV bus bar protection scheme;
- replacement of the protection scheme associated with the 110 kV bus coupler circuit breaker;
- replacement of the protection schemes associated with transformers T1 and T2;
- replacement of the protection schemes associated with feeder bays and 11 kV bus bars; and
- replacement of the substation supervisory control and data acquisition (SCADA).

# 3 PROJECT TIMING

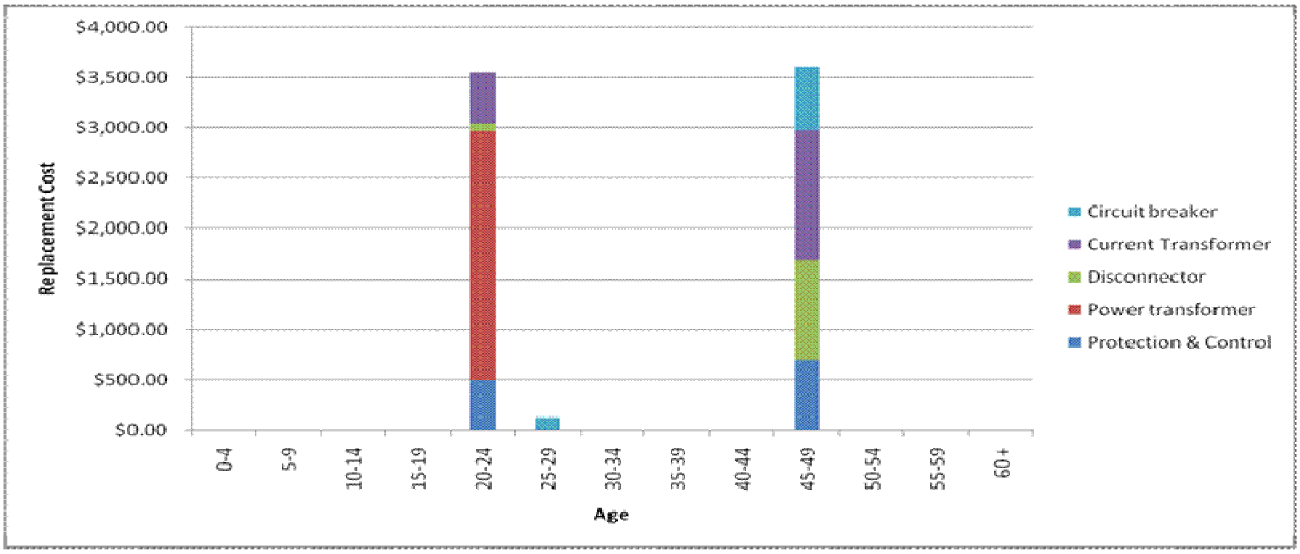
The timing of this project has been co-ordinated with the prioritised 110 kV circuit breaker replacement program and the overall capital works program. This project is currently ranked 22nd of all the projects in Transend's works prioritisation tool and 8th of all the renewal projects.

It is likely that components of this project may need to be implemented prior to the planned commencement of the project because of the deteriorated condition of certain assets and the fact that additional asset condition issues will most likely be identified prior to commencement of the project. It should be noted that these works, should they be needed, will not result in the need for significant rework because the substation is not being reconfigured.

The project is currently scheduled to commence in 2013 and be completed in 2015.

Figure 2 presents a summary of the age of the key 110 kV assets (by category) at Knights Road Substation by asset replacement cost. Figure 2 clearly illustrates that the vast majority of the assets included in the Knights Road Substation 110 kV redevelopment project are well beyond their nominal service lives of 45 years for primary assets and 15 years for secondary assets as defined by Sinclair Knight Merz in its 'Assessment of Economic Lives for Transend Regulatory Asset Classes' report prepared in April 2008 provided as attachment 24 of Transend's revenue proposal.

**Figure 2 - Age and value ($000) of major equipment installed at Knights Road substation**




# 4 INVESTMENT NEED

This project is required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the National Electricity Rules (Rules):

- comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
- maintain the quality, reliability and security of supply of prescribed transmission services; and
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

The key investment driver for this project is to address identified issues presented by the primary and secondary assets at Knights Road Substation.

The key issues relating to each major asset category are discussed in further detail in this section.

## 4.1 CIRCUIT BREAKERS

The 110 kV circuit breakers (five units) installed at Knights Road Substation are Reyrolle type 110/OS/10 units. The 'Reyrolle Type 110/OS/10 110 kV Circuit Breaker Condition Assessment Report' (TNM-CR-806-0772) assesses the condition of Reyrolle circuit breakers and recommends that the units at Knights Road Substation be replaced. The circuit breaker condition assessment has been based on key asset management considerations including technical, design, reliability, condition, maintenance, spares and contingency planning, life-cycle and environment issues. The condition assessment report provides details of the many failures and defects associated with Reyrolle 110 kV circuit breakers, including those installed at Knights Road Substation. The condition assessment report has identified that the Reyrolle circuit breakers:

- have a number of inherent technical and design deficiencies that have adversely impacted transmission circuit reliability and availability;
- are unreliable, in particular the air and insulating oil systems;
- are maintenance intensive and costly to maintain when compared with modern equivalent units;
- require spare parts that are no longer available from the manufacturer's agent;
- require skilled personnel to maintain - the availability of specialised maintenance resources is declining; and
- have reached the end of their useful service lives.

All other transmission companies in Australia and New Zealand have already replaced their population of Reyrolle type 110/OS/10 circuit breakers, or are in the process of doing so, for the same reasons outlined above. Transend's reasons for replacing this type of circuit breaker are no different to those of other industry participants.

The Reyrolle circuit breakers at Knights Road Substation will be 53 years old when decommissioned.

The preventive maintenance costs associated with the 110 kV circuit breakers include:

- circuit breaker maintenance: $7,900 per circuit breaker (six yearly);
- insulating oil costs: $4,200 per circuit breaker (six yearly);
- compressor maintenance: $1,000 per compressor (six-monthly for the two compressors at Knights Road Substation);
- silica gel maintenance: $500 per circuit breaker (two yearly); and
- pressure inspection costs: $300 per circuit breaker (three yearly).

In addition, the average historic repair cost for a failure or defect associated with a Reyrolle type 110/OS/10 circuit breaker is $4,730.

Further information on the circuit breaker population can also be found in the Extra High Voltage Circuit Breaker Asset Management Plan (TNM-PL-809-0541).

## 4.2 VOLTAGE TRANSFORMERS

The 110 kV voltage transformers in service at Knights Road Substation (six single phase units) are ASEA type EMFA 120 units that were manufactured in 1962. The voltage transformers at Knights Road Substation have high percentage power factor readings, which indicate excessive moisture in the insulating oil and likely degradation of the winding insulation. Voltage transformers of this type have failed explosively in the past. The explosive failure of a voltage transformer presents a major safety risk to employees and contractors, should they be working in the vicinity of the voltage transformer at the time of failure. In addition, a major voltage transformer failure would inevitably cause significant disruption to electricity supply.

The EHV Voltage Transformer Asset Management Plan (TNM-PL-809-0614) recommends that the ASEA type EMFA 120 voltage transformers at Knights Road Substation be replaced because they are in poor electrical condition, are susceptible to major failure and are an obsolete design. The voltage transformers will be 53 years old when replaced.

The average maintenance costs associated with 110 kV voltage transformers is $5,500 per three phase set.

This project also includes the installation of voltage transformers on each of the three 110 kV transmission lines that connect to Knights Road Substation to improve the reliability of electricity supply and to reduce the complexity of the associated transmission line protection schemes. Further details of the line voltage transformer installation program and the units that will be installed at Knights Road Substation are provided in the Voltage Transformer Asset Management Plan (TNM-PL-809-00614).

## 4.3 CURRENT TRANSFORMERS

The 110 kV current transformers in service at Knights Road Substation (15 single phase units) are Laur Knudsen type A8ZX units that were manufactured in 1962. A number of units at Knights Road Substation have been identified as having high percentage power factor readings. This type of current transformer utilises a silica gel breather that requires the transmission circuit to be removed from service for maintenance. This deficiency impacts adversely on transmission circuit availability.

The Current Transformer Asset Management Plan (TNM-PL-809-0605) recommends that the Laur Knudsen type A8ZX current transformers be progressively replaced with current transformers installed with the dead-tank circuit breakers because they are generally in poor condition and require frequent maintenance in comparison to modern equivalent units. The current transformers will be 53 years old when decommissioned.

The average preventive maintenance costs associated with 110 kV current transformers at Knights Road Substation is $5,500 per three phase set.

## 4.4 DISCONNECTORS

The 110 kV disconnectors installed at Knights Road Substation (14 units) are Stanger type DR2 units that were manufactured in 1962. Disconnectors A129A, A129B and A129C are mounted on girders approximately 12 metres above ground level. Girder mounted disconnectors cost more to maintain (an additional $300 per unit compared to pedestal mounted disconnectors) because of the additional equipment required to carry out the maintenance at height. It is also more difficult to assess the condition of girder mounted units from ground level. Generally, the Stanger type DR2 disconnectors in service at Knights Road Substation are in a serviceable condition. Given that these disconnectors are operated well within their 800 amp capacity and have proven to be reasonably reliable, they will be refurbished and retained in service at this time. However, the girder mounted units will be replaced with new pedestal mounted units. This approach will reduce ongoing maintenance costs and enhance the ability to assess the condition of the units. It will also provide a number of spare units to sustain the disconnector population.

The average maintenance costs associated with the 110 kV disconnectors is $2,200 per disconnector.

Details of each disconnector type are provided in the Extra High Voltage Disconnector and Earth Switch Asset Management Plan (TNM-PL-809-0606).

## 4.5 POST INSULATORS

The 110 kV post insulators installed at Knights Road Substation (94 units) are NGK type P1141 units. These post insulators are a multi-piece construction that comprise individual insulators bolted together to achieve the required voltage rating. The multi-piece design post insulators are susceptible to mechanical failure in certain operating environments due to moisture freezing within the post insulator, causing the porcelain components to crack. Transend has experienced a significant number of mechanical and electrical failures of EHV multi-piece post insulators over the past 10 years. The consequences of failure have included an increased safety risk to personnel working in switchyards, considerable disruption to electricity supply and the requirement for unplanned outages to facilitate replacement of post insulators.

The Post Insulator Asset Management Plan (TNM-PL-809-0614) recommends that the NGK type P1141 post insulators at Knights Road Substation be replaced.

## 4.6 110 KV BUS BAR PROTECTION

The 110kV bus bar protection at Knights Road Substation is an electromechanical GEC Alstom type CAG scheme, installed in 1962. The CAG is a high impedance scheme, it therefore requires current transformer secondary circuits to be switched through disconnector auxiliary switches. Transend has standardised on the application of low impedance bus bar protection schemes at substations that have double bus bar arrangements (eg Knights Road Substation) to avoid potential substation outages for disconnector auxiliary switch failures. Routine testing of bus bar protection schemes are both expensive and are susceptible to unplanned operations due to finger faults during testing. Replacement of the existing bus bar protection scheme with a modern low impedance scheme will allow routine testing intervals to be increased from three to six years and will significantly reduce the risks associated with finger faults during routine testing.

The EHV Bus Bar Protection Asset Management Plan (TNM-PL-809-0702) recommends that obsolete electromechanical bus bar protection like that in service at Knights Road Substation be replaced with microprocessor based schemes.

## 4.7 TRANSMISSION LINE PROTECTION AND CONTROL SYSTEMS

The distance protection schemes on the Knights Road–Huon River–Kermandie 110 kV transmission line comprised an electromechanical Compagne Des Compteurs type RXAP distance relay and a GEC Alstom type LFZP122 relay. The RXAP relay was replaced on a temporary basis in 2006 because of its poor performance. The upgrade was completed by installing first generation microprocessor relays made available from spares holdings. The microprocessor based relays on this circuit are an ABB type RELZ100 and a GEC Alstom type LFZP122, both manufactured in the early 1990s. Neither of these relays have the capability to capture disturbance records or be remotely interrogated.

The transmission line protection on the Knights Road–Electrona 110 kV transmission line at Knights Road comprises an electromechanical Compagne Des Compteurs type RXAP distance relay and a GEC Alstom type LFZP122 relay. The RXAP was installed in 1963. There are six relays of this type still in service in the transmission network, and there have been three recorded material defects for this type of relay over the past 4 years. The EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) specifically targets the RXAP relays for replacement due to their slow fault clearance times and the high cost of ongoing maintenance.

The transmission line protection at Knights Road on the Chapel Street–Knights Road–Kingston 110 kV transmission line is comprised of a single English Electric type CDG over current protection relay that was installed in 1962. There is a requirement to install a full transmission line protection scheme on this bay to facilitate the operation of the Knights Road–Electrona 110 kV transmission line in a normally closed state.

The EHV Transmission Line Protection Asset Management Plan (TNM-PL-809-0701) identifies the need to progressively replace obsolete protection schemes to sustain the reliability and security of electricity supply and to maintain appropriate spares holdings.

In summary, the majority of the protection relays associated with 110 kV equipment at Knights Road Substation:

- are of obsolete technology;
- are no longer supported by their manufacturer;
- do not have self-diagnostic features; and
- require testing and maintenance on a more frequent basis than modern equivalent assets.

## 4.8 HV PROTECTION AND CONTROL SYSTEMS

The supply transformer and feeder protection schemes at Knights Road substation are static ASEA/ABB Combiflex relays that were installed in 1987. Since 2004, Transend has recorded nine ASEA relay failures out of the 40 relays in-service. Each failure has required the relay to be replaced with a system spare, with the failed relays returned to the supplier for repair. The cost of each failure is approximately $7,000. Though still serviced by ABB at the moment, the relays are not expected to be supported by the manufacturer for much longer. This obsolescence combined with a high failure rate will result in Transend having difficulties maintaining these relays after the current spares holdings are consumed over the next couple of years.

The replacement feeder protection relays will also provide additional benefits:

- live-line settings will be able to be remotely activated;
- impedance to fault figures will be available at the Network Operations Control Centre; and

- dial-up access to relays for engineering functions, event logs and fault recording data.

This project will provide the following benefits that will ultimately improve the performance of the power system:

- better protection coordination with Aurora's distribution network;
- better power quality monitoring and assessment;
- remote monitoring, interrogation and adjustment capability; and
- improved fault location leading to reduced outage duration.

The existing relays are a static type, which require testing at 3 yearly intervals. The proposed microprocessor type relays have self-diagnostic features and require testing at 6 yearly intervals. This will result in operational savings and a reduction in the risk of inadvertent system outages during the intrusive testing of the protection systems.

The new microprocessor based protection schemes will provide in-built disturbance recording features that enable easy post-fault diagnosis and faster outage restoration. These features will reduce ongoing operational costs associated with fault investigations. The installation of remote interrogation facilities will also reduce operational expense of uploading these disturbance records.

The High Voltage Substation Protection Asset Management Plan (TNM-PL-809-0706) recommends that obsolete static protection schemes be progressively replaced and where appropriate, be integrated with other planned works.

### 4.9 HV SCADA SYSTEM

The existing SCADA remote terminal unit (RTU) at Knights Road Substation is a Harris D20 installed in 1997 as part of a program to remote control transmission substations. The Harris D20 RTU is not compatible with current IED technology because it does not support TCP/IP connections and has limited serial connectivity. It is therefore important that the SCADA scheme is replaced early in the project to ensure that new protection panels are able to appropriately communicate alarms, events and controls back to Transend's Network Operations Control System (NOCS).

Transend's standard SCADA scheme incorporates a local area network (LAN) for engineering access to protection and control devices. An Engineering PC connected to the substation LAN enables all devices to be interrogated for disturbance records, fault locations and to undertake setting modifications. Connecting the Engineering PC to the WAN allows these activities to be undertaken remotely.

A local human machine interface (HMI) PC will be installed at the substation. The HMI allows Field Operators to control and monitor the substation in the event of loss of remote control from NOCs. The HMI is able to log substation events at a higher resolution than can be sent back to NOCS, which is vital for post fault analysis.

Redevelopment of Knights Road Substation 110 kV provides the opportunity to cost-effectively install a modern, reliable SCADA system that provides additional functionality and remote monitoring capability.

## 5 CUSTOMER CONSULTATION

Transend will liaise directly with relevant stakeholders regarding the intent, scope and implementation of the project. The proposed redevelopment project has been highlighted on a number of occasions during Transend's Annual Planning Review process.

## 6 BENEFITS

The direct benefits of redeveloping Knights Road Substation 110 kV include:

- it will contribute to the achievement of the capital expenditure objectives identified in the Rules;
- provision of a safe, secure and reliable electricity supply to customers connected to Knights Road, Huon River and Kermandie substations by replacing obsolete, unreliable assets that are in poor condition;
- life-cycle cost savings due to reduced operations and maintenance requirements;

- reduced burden on spare parts management by using standard equipment;
- provide additional functionality and remote monitoring capability;
- alignment with strategic asset management plans; and
- location of equipment which allows for future expansion.

# 7 OPTIONS ANALYSIS

The following options have been considered for the redevelopment of Knights Road Substation:

1. manage existing assets and defer replacement;
2. replace selected assets in situ;
3. staged replacement of selected assets in situ; and
4. replace all assets in situ.

Other options considered at a high-level, but discounted for the reasons mentioned include:

- **Offsite greenfield development** - not considered to be a cost effective alternative as other solutions can be implemented within the existing perimeter of Knights Road Substation at a substantially lower cost.

## 7.1 OPTION 1: MANAGE EXISTING ASSETS AND DEFER REPLACEMENT

### 7.1.1 SCOPE

The scope for this option includes:

- replace assets that are known to present a significant safety risk, including post insulators and voltage transformers in 2014;
- replace protection and control schemes due to condition and customer request;
- continue existing maintenance practices, albeit accelerated due to the declining condition and ageing of assets;
- undertake repairs and corrective maintenance as required; and
- defer replacement of certain assets for up to five years.

The capital cost of this option includes an initial $6.74 million ($June 2007) to address safety issues followed by a deferred capital cost of $1.65 million ($June 2007) to replace remaining 110 kV assets five years later.

### 7.1.2 BENEFITS

The benefit for this option is the deferral of capital expenditure and that the identified safety issues are addressed.

### 7.1.3 DRAWBACKS

The drawbacks for this option are that it would:

- not allow Transend to achieve the capital expenditure objectives;
- not satisfactorily address the performance, reliability and design issues associated with circuit breakers and current transformers identified in section 4;
- incur increased ongoing operating expenditure due to increased maintenance, condition monitoring requirements and corrective maintenance requirements;
- not be sustainable given the reliability issues associated with the 110 kV primary and secondary assets, in particular the circuit breakers, current transformers and protection and control equipment;
- result in an increased number of loss of electricity supply events at Knights Road Substation when compared with other options;

- incur significantly longer and more frequent outages due to the intensive maintenance regimes that would be required to maintain the existing assets in service (whilst recognising that this approach is almost certainly unlikely to be successful);
- not align with Transend's policy to utilise dead tank circuit breakers when replacing 110 kV live tank current transformers and circuit breakers; and
- not align with the recommendations made in the respective asset management plans for the primary and secondary assets.

### 7.1.4 CONCLUSION

Although this option may have lower initial capital cost, it is not the preferred option because it does not ensure the reliable operation of Knights Road Substation.

## 7.2 OPTION 2: REPLACE SELECTED ASSETS IN-SITU

### 7.2.1 SCOPE

The scope for this option includes the replacement of the following assets in 2014:

- in-situ replacement of assets that are known to present a significant safety risk, including post insulators, voltage transformers and current transformers;
- replacement of the existing live tank circuit breakers with dead tank units with integral current transformers;
- replacement of voltage transformers in-situ;
- replacement of multi-piece post insulators with new units in-situ;
- replacement of all droppers with aluminium conductor and compression fittings;
- replacement of the identified protection and control schemes; and
- implementation of revised maintenance practices.

The capital cost of this option is $7.44 million ($June 2007).

### 7.2.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;
- addresses the safety and performance issues associated with the 110 kV assets identified in section 4 of this document, in particular the 110 kV voltage transformers and post insulators;
- addresses other performance, reliability and design issues identified in section 4; and
- reduces the ongoing maintenance requirements and costs associated with the site.

### 7.2.3 DRAWBACKS

The option has the following drawbacks:

- higher initial capital cost than option 1.

### 7.2.4 CONCLUSION

This option is technically viable.

## 7.3 OPTION 3: STAGED REPLACEMENT OF SELECTED ASSETS IN-SITU

### 7.3.1 SCOPE

The scope for this option is essentially the same as option 2, but implemented using a staged approach based on transmission circuit criticality. This option includes:

- initial replacement of assets that have an assigned transmission circuit criticality rating of four or five (three bays); and
- initial replacement of other assets that are known to present a safety risk, including post insulators, voltage transformers and current transformers; and
- deferred replacement of the remaining 110 kV assets by up to three years (two bays).

The capital cost of this option includes an initial $1.55 million ($June 2007) to replace critical assets and to address safety issues followed by a deferred capital cost of $6.36 million ($June 2007) to replace remaining 110 kV assets three years later.

### 7.3.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives in the mid-term;
- addresses the safety issues associated with the 110 kV assets identified in section 4 of this document;
- defers capital expenditure associated with replacing the 110 kV disconnectors;
- defers capital expenditure associated with lower criticality assets for up to 3 years;
- addresses the performance issues identified in section 4 of this document, with the exception of those transmission circuits that have a criticality less than four; and
- reduces the ongoing maintenance requirements and costs associated with the site.

### 7.3.3 DRAWBACKS

The drawbacks for this option are that it:

- results in a higher overall capital cost than option 2, primarily due to the use of live tank circuit breakers, contractor remobilisation and increased internal costs;
- does not align with Transend’s policy to utilise dead tank circuit breakers when replacing 110 kV live tank current transformers and circuit breakers for two 110 kV bays; and
- will need additional transmission circuit outages to undertake the works.

### 7.3.4 CONCLUSION

This option is technically viable.

### 7.4 OPTION 4: COMPLETE REDEVELOPMENT OF KNIGHTS ROAD SUBSTATION 110 KV

#### 7.4.1 SCOPE

The scope for this option includes:

- in-situ replacement of the existing live tank circuit breakers with dead tank units with integral current transformers;
- replacement of 110 kV disconnectors in situ;
- replacement of gantry structures;
- replacement of protection and control schemes; and
- implement revised maintenance practices.

The capital cost of this option is $8.58 million ($June 2007).

#### 7.4.2 BENEFITS

The benefits for this option are that it:

- would allow Transend to achieve the capital expenditure objectives;
- addresses the asset and safety issues associated with the 110 kV assets identified in section 4, in particular the 110 kV voltage transformers and post insulators;
- addresses other performance, reliability and design issues identified in section 4; and
- reduces the ongoing maintenance requirements and costs associated with the site.

#### 7.4.3 DRAWBACKS

The option has the following drawbacks:

- higher capital cost than option 2.

#### 7.4.4 CONCLUSION

This option is technically viable.

## 8 OPTION ESTIMATES

A comparison of the net present value of options is provided in Table 2.

**Table 2 - Comparison of options considered**

| Option | | Net present value of costs ($M June 2007) |
|---|---|---|
| 1 | Manage existing assets and defer replacement | -$5.21 |
| 2 | Replace selected assets in-situ | -$4.71 |
| 3 | Staged replacement of selected assets in-situ | -$4.87 |
| 4 | Complete redevelopment of Knights Road Substation 110 kV | -$5.23 |

The economic analysis includes the cost impact to customers in the event of a major circuit breaker failure using a probabilistic approach based on current and forecast load data for each individual transmission circuit connected to Knights Road Substation 110 kV.

# 9 PREFERRED OPTION

Option 2 (replace selected assets in-situ) is the least cost option that addresses the identified safety, reliability, condition and design issues at Knights Road Substation. This option also minimise the number and duration of transmission circuit outages due to reduced frequency and duration of maintenance.

Further detailed analysis will be undertaken during the project initiation process to ensure that the information and assumptions which have been used to identify the preferred option are still valid.

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | MEADOWBANK SUBSTATION 110 KV REDEVELOPMENT |
| **TRIM NUMBER** | D09/3698 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 2.0 |
| **TRANSEND CONTACT** | INDUNIL VITHANAGE |
| **PROJECT NUMBER** | ND0949 |

## ATTACHMENT A6

# CONTENTS

# 1 BACKGROUND

Meadowbank Substation provides electricity supply to customers connected in the Gretna, Hamilton, Bothwell, Ouse and Oatlands areas. In addition, the substation provides a connection point for power generated from Meadowbank Power Station. The majority of 110 kV assets in service at Meadowbank Substation were installed when the substation was commissioned in 1963. Figure 1 presents an image of Meadowbank Substation.

**Figure 1 - Aerial view of Meadowbank Substation**

# 2 PROJECT OVERVIEW

The planned redevelopment of Meadowbank Substation includes the replacement of 110 kV circuit breakers, voltage transformers and post insulators and protection and control equipment. The redevelopment will address safety issues and improve the reliability of electricity supply by replacing assets that are in poor condition and susceptible to failure.

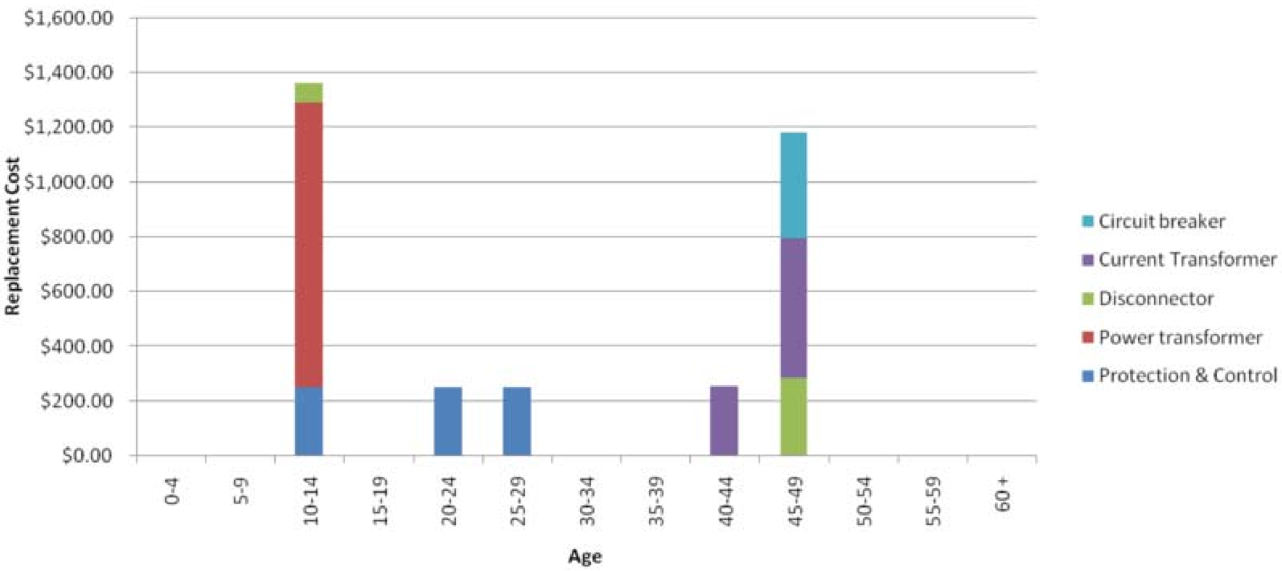
This project includes the following major works at Meadowbank Substation:

- replacement of Reyrolle type 110/OS/10 110 kV circuit breakers;
- replacement of Balteau type UEV110 and Ducon type PD 110 kV voltage transformers;
- installation of 110 kV voltage transformers on each transmission line;
- refurbish and retain the ABB, Stanger and Switchgear Pty Ltd disconnectors;
- replacement of multi-piece post insulators;
- replacement of the 110 kV Tarraleah – Meadowbank transmission line protection;

- replacement of the 110 kV Meadowbank – New Norfolk transmission line protection;
- extend the switch house to provide for the planned replacement of the secondary and ancillary equipment; and
- replacement of the substation supervisory control and data acquisition (SCADA).

Figure 2 presents a summary of the age of the key 110 kV assets (by category) at Meadowbank Substation by asset replacement cost (note that the scope of the project does not include replacement of the power transformers, disconnectors or high voltage switchgear and associated protection). Figure 2 clearly illustrates that the vast majority of the assets included in the Meadowbank Substation 110 kV redevelopment project are well beyond their nominal service lives of 45 years for primary assets and 15 years for secondary assets as defined by Sinclair Knight Merz in its 'Assessment of Economic Lives for Transend Regulatory Asset Classes' report provided as attachment 24 to Transend's revenue proposal.

**Figure 2 – Summary age and value ($000) of major equipment installed at Meadowbank Substation**




# 3 PROJECT TIMING

The timing of this project has been co-ordinated with the prioritised 110 kV circuit breaker replacement program and the overall capital works program. The project is currently scheduled to commence in 2012 and be completed in 2014.

# 4 INVESTMENT NEED

This project is required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the National Electricity Rules:

- comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
- maintain the quality, reliability and security of supply of prescribed transmission services; and
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

The key investment driver for this project is to address identified safety, condition, reliability and design risks associated with primary and secondary assets at Meadowbank Substation.

## 4.1 CIRCUIT BREAKERS

The 110 kV circuit breakers (three units) installed at Meadowbank Substation are Reyrolle type 110/OS/10 units. The Reyrolle Type 110/OS/10 110 kV Circuit Breaker Condition Assessment Report (TNM-CR-806-0772) assesses the condition of Reyrolle type 110/OS/10 circuit breakers and recommends that the units at Meadowbank Substation be replaced. The circuit breaker assessment has been based on key asset management considerations, including technical, design, reliability, condition, maintenance, spares and contingency planning, life-cycle and environment issues. The condition assessment report provides details of the many failures and defects associated with Reyrolle 110 kV circuit breakers, including those installed at Meadowbank Substation. The condition assessment report has identified that the Reyrolle type 110/OS/10 circuit breakers:

- have a number of inherent technical and design deficiencies that have adversely impacted transmission circuit reliability and availability;
- are unreliable, in particular the air and insulating oil systems;
- are maintenance intensive and costly to maintain when compared with modern equivalent units;
- require spare parts that are no longer available from the manufacturer's agent;
- require skilled personnel to maintain - the availability of specialised maintenance resources is declining; and
- have reached the end of their useful service lives.

All other transmission companies in Australia and New Zealand have already replaced their population of Reyrolle type 110/OS/10 circuit breakers, or are in the process of doing so, for the same reasons outlined above. Transend's reasons for replacing this type of circuit breaker are no different to those of other industry participants.

The 110 kV circuit breakers at Meadowbank Substation will be 52 years old when decommissioned, and will have exceeded their assigned class life of 45 years as defined by Sinclair Knight Merz in its Assessment of Economic Lives for Transend Regulatory Classes, April 2008.

The preventive maintenance costs associated with the 110 kV circuit breakers at Meadowbank Substation include:

- circuit breaker maintenance: $8 300 per circuit breaker (six yearly);
- insulating oil costs: $4 200 per circuit breaker (six yearly);
- compressor maintenance: $1 000 per compressor (six-monthly for the compressor at Meadowbank Substation);
- silica gel maintenance: $500 per circuit breaker (two yearly); and
- pressure inspection costs: $300 per circuit breaker (three yearly).
- In addition, the average historic repair cost for a failure or defect associated with a Reyrolle type 110/OS/10 circuit breaker is $4 730.

Further information on the circuit breaker population can also be found in the Extra High Voltage Circuit Breaker Asset Management Plan (TNM-PL-809-0541).

## 4.2 VOLTAGE TRANSFORMERS

The 110 kV voltage transformers installed at Meadowbank Substation comprise the following types:

- Balteau type UEV110 - 3 units (average age of 30 years); and
- Ducon type PD - 2 units (45 years).

**Balteau voltage transformers**

The Balteau type UEV110 voltage transformers have a number of design deficiencies, including:

- the design is susceptible to moisture ingress. Instances of moisture ingress through the diaphragm have occurred, which has resulted in the high percentage power factor readings of other Balteau units installed in the transmission network;
- a poorly designed oil-level sight glass. The sight glass is susceptible to mechanical failure and vandalism. The failure of a sight glass will allow moisture to enter the expansion chamber and pool on the rubber diaphragm. It is extremely difficult to assess the integrity of the sight glass with the voltage transformer in service; and
- units do not have oil-sampling facilities.

Moisture ingress in the insulating oil degrades the winding insulation and increases the risk of explosive failure. While Transend has not experienced any major failures of Balteau voltage transformers, other Australian transmission companies have reported explosive failures of Balteau voltage transformers of a similar design. The explosive failure of a voltage transformer presents a major safety risk to employees and contractors working in the vicinity of the voltage transformer at the time of failure.

The EHV Voltage Transformer Asset Management Plan (TNM-PL-809-0614) recommends that Balteau type UEV110 voltage transformers be replaced.

**Ducon voltage transformers**

Ducon type PD 110 kV voltage transformers are approaching the end of their service lives, have inherent design deficiencies and are susceptible to explosive failure. Transend has experienced explosive failures of Ducon 110 kV voltage transformers at Palmerston Substation in 2001 and at Avoca Substation in March 2008. Both failures resulted in a fire of the voltage transformer. Figure 3 presents an image of a failed Ducon 110 kV voltage transformer and porcelain fragments in the switchyard.

**Figure 3 – Explosive failure of a Ducon 110 kV voltage transformer at Avoca Substation (March 2008)**


Ducon voltage transformers that were manufactured prior to 1973 incorporated a unique gasketing system where a neoprene rubber gasket was encased within a lead sheath to protect the rubber from the insulating oil. As the units age, the lead sheath becomes susceptible to creeping inward causing lead to fall inside the unit, or the rubber to be exposed to the insulating oil which hardens the rubber and results in deterioration of the oil seal.

The EHV Voltage Transformer Asset Management Plan (TNM-PL-809-0614) recommends that Ducon type PD voltage transformers at Meadowbank Substation be replaced.

The average preventive maintenance costs associated with 110 kV voltage transformers at Meadowbank Substation is $5 500 per three phase set.

## 4.3 CURRENT TRANSFORMERS

The 110 kV current transformers in service at Meadowbank Substation (nine single phase units) are Laur Knudsen type A8ZX units that were manufactured in 1963. A number of identical current transformers installed elsewhere in the transmission system have been identified as having high percentage power factor readings. This type of current transformer utilises a silica gel breather that requires the transmission circuit to be removed from service for maintenance. This deficiency impacts adversely on transmission circuit availability.

The Current Transformer Asset Management Plan (TNM-PL-809-0605) recommends that the Laur Knudsen type A8X current transformers be progressively replaced with current transformers installed with the dead-tank circuit breakers because they are generally in poor condition and require frequent maintenance in comparison to modern equivalent units. The current transformers will be 52 years old when decommissioned.

The average preventive maintenance costs associated with 110 kV current transformers at Meadowbank Substation is $5 500 per three phase set.

## 4.4 DISCONNECTORS

The 110 kV disconnectors installed at Meadowbank Substation comprise the following types:

- ABB type DBRP - 1 unit (age 12 years);
- Stanger type DR2 - 3 units (average age 46 years); and
- Switchgear Pty Ltd type DBR-4 - 1 unit (age 46 years).

Generally, the ABB, Stanger and Switchgear Pty Ltd disconnectors in service at Meadowbank Substation are in a serviceable condition. Given that these disconnectors have proven to be reasonably reliable, they will be refurbished and retained in service at this time.

The average preventive maintenance costs associated with 110 kV disconnectors at Meadowbank Substation is $2 000 per unit.

Details of each disconnector type are provided in the Extra High Voltage Disconnector and Earth Switch Asset Management Plan (TNM-PL-809-0606).

## 4.5 POST INSULATORS

The 110 kV post insulators (approximately 45 units) installed at Meadowbank Substation are a multi-piece construction that comprise individual insulators bolted together to achieve the required voltage rating. The multi-piece design post insulators are susceptible to mechanical failure in certain operating environments due to moisture freezing within the post insulator, causing the porcelain components to crack. Transend has experienced a significant number of mechanical and electrical failures of EHV multi-piece post insulators over the past 10 years. The consequences of failure have included an increased safety risk to personnel working in switchyards, considerable disruption to electricity supply and the requirement for unplanned outages to facilitate replacement of post insulators.

The post insulator asset management plan (TNM-PL-809-0614) recommends the progressive replacement of all multi-piece post insulators.

## 4.6 CONTROL BUILDING

The control building at Meadowbank Substation was designed for the secondary and ancillary systems associated with the 110 kV assets. There is insufficient space available in the control building to facilitate the planned replacement of secondary and ancillary systems without disrupting the existing equipment. Extending the control building is not feasible without major 110 kV asset relocations. Due to this constraint, a new switch house was constructed in 2001 for the 22 kV switchgear and associated protection and control systems. This project includes the extension of the 22 kV switch house be to provide a greenfield area for the planned replacement of secondary and ancillary equipment. Replacing secondary and ancillary equipment at greenfield locations is common practice for transmission network service providers and has been adopted by Transend for a number of previous projects. This approach has the following advantages:

- the likelihood of interruption to electricity supply is minimised;

- secondary and ancillary equipment can be installed and pre-commissioned prior to the outage, reducing circuit outage duration; and
- protection and control panels can be arranged in a logical order.

## 4.7 PROTECTION AND CONTROL

**Tarraleah – Meadowbank Transmission Line Protection**

The protection scheme comprises of an ASEA RAZOA distance relay, a Brown Boveri LZ92 distance relay, and a Schlumberger PSEL3002 high impedance earth fault relay. The scheme has no permissive inter-tripping communications circuits from either distance relay.

The ASEA RAZOA is a static relay which was installed in 1988. This type of relay has no recorded defects over the past 5 years and there are currently 6 installed around the state with 3 spare relays available. The spare relays would have been removed from previous installations.

The Brown Boveri LZ92 is a static relay which was installed in 1988. This type of relay has no recorded defect over the past 5 years and there are currently 12 installed around the state with 2 spare relays available. The spare relays would have been removed from previous installations.

The Schlumberger PSEL3002 is a static relay which was installed in 1988. This type of relay has no recorded defect over the past 5 years and there are currently 6 installed around the state with 2 spare relays available. The spares would have been removed from previous installations.

**Meadowbank – New Norfolk Transmission Line Protection**

The protection scheme comprises of a Mitsubishi MDT-B151 distance relay, a Reyrolle THR distance relay, and a Schlumberger PSWS high impedance earth fault relay. The scheme has no permissive inter-tripping communications circuits from either distance relay. The protection schemes associated with the Meadowbank–New Norfolk 110 kV transmission line do not meet the clearance time requirements of the National Electricity Rules (NER) for a three-phase fault due to the absence of an accelerated scheme (refer section 5.2 protection audit TRIM D06/31945). The potential impact of this non-compliance is the loss of synchronism at Meadowbank Power Station for a transmission line fault.

The Mitsubishi MDT-B151 is a static relay which was installed in 1981. This type of relay has 3 recorded defects over the past 5 years and there are currently 8 installed around the state with 3 spare relays available.

The Reyrolle THR is a static relay which was installed in 1981. This type of relay has 5 recorded defects over the past 5 years and there are currently 20 installed around the state with 4 complete spare relay sets.

The Schlumberger PSWS is a static relay which was installed in 1981. This type of relay has 1 recorded defect over the past 5 years and there are currently 22 installed around the state with 4 spare relays available. The spares would have been removed from previous installations.

The protection installations at Meadowbank substation are contained within open panels with exposed terminals that are susceptible to dust, moisture, and vermin.

Transend has standardised on the installation of duplicated current differential schemes on its transmission lines where practicable. Current differential protection has a distinct advantage over distance protection because it is immune to under or over reaching as a result of varying zero sequence mutual impedances. By replacing the transmission line protection at Meadowbank Substation at the same time as the remote ends, Transend will improve protection co-ordination and improve transmission network performance. If the replacement of protection systems at either end of transmission line is undertaken years apart there is a significant likelihood that compatible current differential relays will not be available. Given the fast rate of change in relay technology, it is prudent to replace protection systems at both ends of transmission line at the same time.

The replacement of these static relays in conjunction with the associated primary equipment aligns with strategy detailed in the Transmission Line Protection Asset Management plan (TNM-PL-809-0701). These relays are a static design, which:

- are obsolete technology;
- do not have self-diagnostic features;
- require testing and maintenance on a more frequent basis than modern equivalent assets; and
- are no longer supported by manufacturers.

The EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) recommends that the protection schemes associated with the Meadowbank–New Norfolk 110 kV and Tarraleah–Meadowbank 110 kV transmission lines at Meadowbank Substation be replaced. The standard EHV protection panel has the following features:

- duplicate current differential protection;
- back up distance protection function;
- auto reclose functionality;
- synchronism check;
- control functionality such as disconnector and earth switch interlocking logic;
- multiple setting groups;.
- fault recording functions; and
- fault location functionality.

The average preventive maintenance costs associated with the protection and control systems that are scheduled for replacement at Meadowbank Substation is $4 200 per scheme (three yearly).

### 4.8 SUPERVISORY CONTROL AND DATA ACQUISITION

The existing supervisory control and data acquisition (SCADA) remote terminal unit (RTU) is a Harris D20M++ installed in 1996, as part of a program to remote control transmission substations. The RTU has suffered a number of lock-ups due to memory buffer overflows during periods of high activity. Each lock-up requires a technician to attended site to clear error logs. The RTU is not compatible with current IED technology because it does not support TCP/IP connections and has limited serial connectivity. It is therefore important that the SCADA scheme be replaced early in the project to ensure that new protection panels are able to communicate alarms and events and controls back to Transend's Network Operations System (NOCS). The D20M++ is no longer supported by the manufacturer and Transend has limited spares holdings.

The RTU communicates to the NOCS in Conitel protocol as opposed to the modern industry standard of DNP3. The Conitel protocol has several limitations, is not able to send time stamped sequence of events to NOCS and it takes extended amount of time to transmit data (latency issue). Converting a RTU to DNP3 requires the re-commissioning of all substation points back to NOCS, it is proposed to undertake this work as part of this redevelopment.

Transend's standard SCADA scheme incorporates a local area network (LAN) for engineering access to protection and control devices. An Engineering PC installed at the substation LAN enables all devices to be interrogated for disturbance records and setting modifications. Connecting the Engineering PC to the WAN allows these activities to be undertaken remotely at Transend office locations.

## 5 CUSTOMER CONSULTATION

Transend will liaise directly with relevant stakeholders regarding the intent, scope and implementation of the project. Extensive consultations have been held with Hydro Tasmania over the past few years with respect to the relocation of Hydro Tasmania's secondary assets. Based on present information, Transend is confident that it will achieve appropriate resolution on the issues of relocation. This will allow the project to proceed as forecast in the revenue proposal.

## 6 BENEFITS

The direct benefits that are achieved through completing the work outlined in the scope are:

- it will contribute to the achievement of the capital expenditure objectives indentified in the Rules;
- provision of a safe, secure and reliable electricity supply to customers connected to Meadowbank Substation by replacing obsolete, unreliable assets that are in poor condition;
- provide improved functionality and remote monitoring capability;
- alignment with strategic asset management plans;
- life-cycle cost savings due to reduced operations and maintenance requirements; and

- reduced burden on spare parts management by using standard equipment.

# 7 OPTIONS ANALYSIS

The following options have been considered for the redevelopment of Meadowbank Substation:

1. Manage existing 110 kV assets and defer replacement;
2. Replace selected 110 kV assets; and
3. Replace all 110 kV assets.

Other options considered at a high-level, but discounted for the reasons mentioned include:

- **Off-site greenfield development** - not considered to be a cost effective alternative as other solutions can be implemented within the existing perimeter of Meadowbank Substation at a substantially lower cost. This option was also discounted for the following reasons:
  - the terrain surrounding the area is rugged and uneven, which makes it difficult to find a level ground suitable for a new development within close proximity to the power station and transmission lines; and
  - part of the switchyard has been redeveloped in recent years (high voltage switchgear replacement, building and security fence).

## 7.1 OPTION 1: MANAGE EXISTING 110 KV ASSETS AND DEFER REPLACEMENT

### 7.1.1 SCOPE

The scope for this option includes:

- replace assets that present a safety risk, including post insulators, voltage transformers and current transformers;
- continue existing maintenance practices, albeit accelerated due to the declining condition and ageing of assets.
- undertake repairs and corrective maintenance as required.
- defer replacement for up to five years.

The capital cost of this option includes an initial $4.51 million ($June 2007) to address safety issues followed by a deferred capital cost of $1.05 million ($June 2007) to replace remaining 110 kV assets five years later.

### 7.1.2 BENEFITS

The benefit for this option is the deferral of capital expenditure.

### 7.1.3 DRAWBACKS

The drawbacks for this option are that it:

- does not allow Transend to achieve the capital expenditure objectives;
- does not address the performance, reliability and design issues associated with circuit breakers and current transformer identified in section 4;
- does not address the NER compliance issues associated with the Meadowbank–New Norfolk 110 kV transmission line protection scheme;
- incurs increased ongoing operating expenditure due to increased maintenance, condition monitoring requirements and corrective maintenance requirements;
- is not sustainable given the reliability issues associated with the 110 kV assets, in particular the circuit breakers and current transformers;
- incurs longer and more frequent outages due to maintenance regimes that are required to maintain the existing assets; and
- involves an increased risk of loss of supply events at Meadowbank Substation when compared with other options;
- has the potential to cause voltage issues in the southern region of Tasmania; and
- does not align with the recommendations made in respective asset management plans for primary and secondary equipment.

#### 7.1.4 CONCLUSION

Although this option has lower initial capital cost, it is not the preferred option because it does not ensure the reliable operation of Meadowbank Substation and does not address NER compliance issues.

### 7.2 OPTION 2: REPLACE SELECTED 110 KV ASSETS IN-SITU

#### 7.2.1 SCOPE

The scope for this option includes:

- in-situ replacement of the existing live tank circuit breakers with dead tank units with integral current transformers;
- replacement of voltage transformers in-situ;
- replacement of multi-piece post insulators with new units in-situ;
- replacement of all droppers with aluminium conductor and compression fittings;
- replacement of protection and control schemes; and
- implement revised maintenance practices.

The capital cost of this option is $4.93 million ($June 2007).

#### 7.2.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;
- addresses the asset and safety issues associated with the 110 kV assets identified in section 4, in particular the 110 kV voltage transformers and post insulators;
- addresses the NER compliance issues associated with the Meadowbank–New Norfolk 110 kV transmission line protection scheme;
- addresses other performance, reliability and design issues identified in section 4; and
- reduces the ongoing maintenance requirements and costs associated with the site.

#### 7.2.3 DRAWBACKS

The option has the following drawbacks:

- higher initial capital cost than option 1.

#### 7.2.4 CONCLUSION

This option is technically viable.

### 7.3 OPTION 3: REPLACE ALL 110 KV ASSETS IN-SITU

#### 7.3.1 SCOPE

The scope for this option includes:

- in-situ replacement of the existing live tank circuit breakers with dead tank units with integral current transformers;
- replacement of 110 kV disconnectors in situ (excluding disconnector A429);
- replacement of gantry structures;
- replacement of protection and control schemes; and
- implement revised maintenance practices.

The capital cost of this option is $4.33 million ($June 2007).

#### 7.3.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;

- addresses the asset and safety issues associated with the 110 kV assets identified in section 4, in particular the 110 kV voltage transformers and post insulators;
- addresses other performance, reliability and design issues identified in section 4;
- addresses the NER compliance issues associated with the Meadowbank–New Norfolk 110 kV transmission line protection scheme;
- enables reduced outage duration and ease of implementation (refer to Appendix A for proposed implementation sequence); and
- reduces the ongoing maintenance requirements and costs associated with the site.

### 7.3.3 DRAWBACKS

The option has the following drawbacks:

- higher capital cost than option 2.

### 7.3.4 CONCLUSION

This option is technically viable.

# 8 OPTION ESTIMATES

A comparison of the net present value of options is provided in Table 1.

**Table 1 - Comparison of options considered**

| Option | | Net present value of costs ($M June 2007) |
|---|---|---|
| 1 | Manage existing 110 kV assets and defer replacement | -$2.84 |
| 2 | Replace selected 110 kV assets in-situ | -$2.65 |
| 3 | Replace all 110 kV assets in-situ | -$3.37 |

The economic analysis includes the cost impact to customers in the event of a major circuit breaker failure using a probabilistic approach based on current and forecast load data for each individual transmission circuit connected to Meadowbank Substation 110 kV.

# 9 PREFERRED OPTION

Option 2 (replacement of selected 110 kV assets) is the preferred option because it is the most cost effective solution to address the identified safety, reliability, condition and design issues at Meadowbank Substation. This approach will also minimise the number and duration of transmission circuit outages due to reduced frequency and duration of maintenance.

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | PALMERSTON SUBSTATION 110 KV REDEVELOPMENT |
| **TRIM REFERENCE** | D09/3258 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 2.0 |
| **TRANSEND CONTACT** | DAVID KRUIJVER |
| **PROJECT NUMBER** | ND0953 |

## ATTACHMENT A7

# CONTENTS

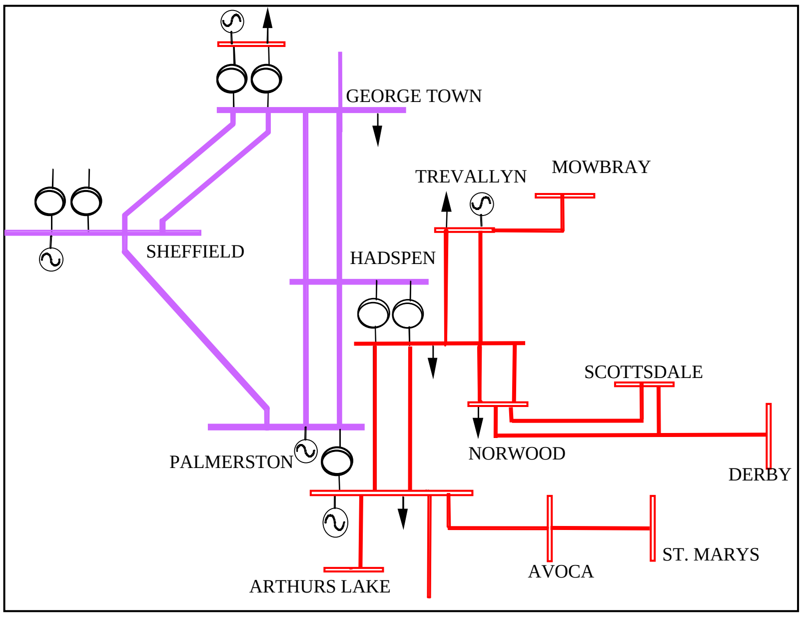
# 1 BACKGROUND

Palmerston Substation 110 kV is critical to ensuring a secure and reliable electricity connection point for customers and generators in northern Tasmania. Palmerston Substation 110 kV provides:

- an interconnection to Palmerston Substation 220 kV via a 200 MVA auto-transformer;
- two transmission lines to Hadspen Substation;
- an interconnection to Waddamana Substation in southern Tasmania;
- a radial supply to Avoca and St Marys substations;
- a radial supply to Arthurs Lake Substation;
- two 110/22 kV connections to Aurora Energy; and
- two connections to Hydro Tasmania's Poatina power station.

Figure 1 presents the schematic diagram of the northern Tasmanian transmission network that connects to Palmerston Substation.

**Figure 1 - Northern area transmission network schematic diagram**




The majority of the existing 110 kV assets in service at Palmerston Substation were installed when the 110 kV switchyard at Palmerston Substation was commissioned in 1963.

# 2 PROJECT OVERVIEW

The planned redevelopment of Palmerston Substation 110 kV primarily includes the replacement of circuit breakers, voltage transformers, post insulators, and selected protection and control equipment. The substation redevelopment will address the identified safety issues and improve the security and reliability of electricity supply by replacing assets that are in poor condition and susceptible to failure.

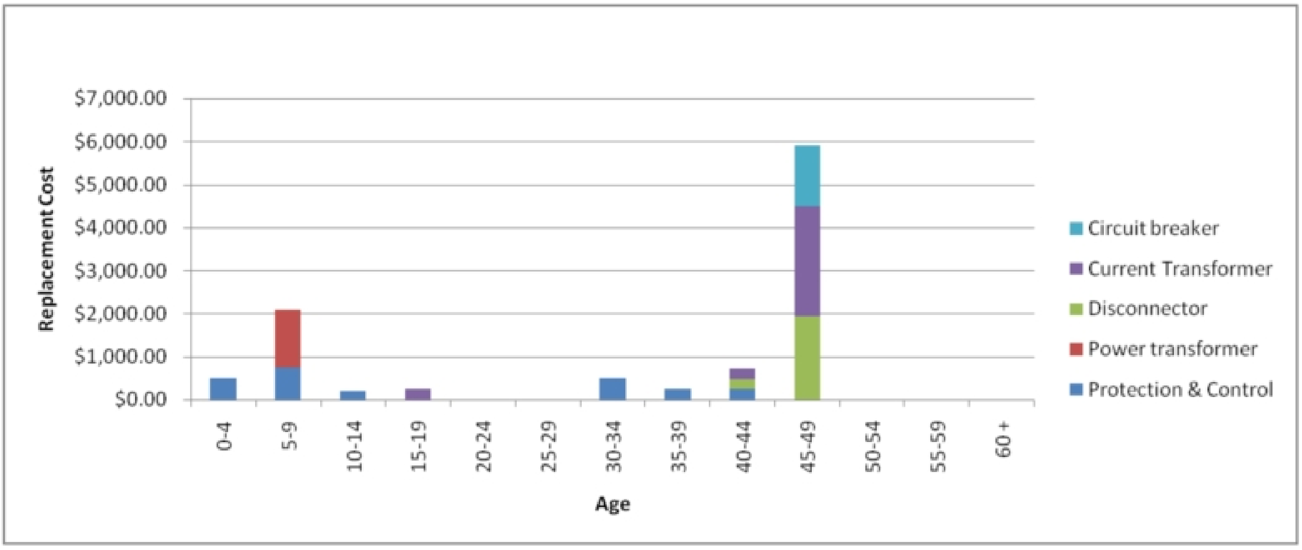
This project includes the following major works at Palmerston Substation 110 kV:

- replacement of 11 Reyrolle type 110/OS/10 circuit breakers with dead tank circuit breakers that have integral current transformers;
- refurbishment of 28 disconnectors including replacement of the multi-piece post insulators;

- replacement of six three phase sets of voltage transformers (including one set at St Marys Substation);
- installation of two three-phase sets of voltage transformers;
- decommissioning of the existing post type current transformers;
- replacement of multi-piece post insulators;
- replacement of the Palmerston–Arthurs Lake 110 kV transmission line protection;
- replacement of the Palmerston–Avoca 110 kV transmission line protection;
- replacement of the Palmerston–Hadspen No. 3 110 kV transmission line protection; and
- replacement of the Palmerston–Hadspen No. 4 110 kV transmission line protection.

Figure 2 presents a summary of the age of the key 110 kV assets (by category) at Palmerston Substation by asset replacement cost (note that the scope of this project does not include replacement of the power transformers, disconnectors and selected protection and control systems). Figure 2 clearly illustrates that the vast majority of the assets included in the Palmerston Substation 110 kV redevelopment project are well beyond their nominal service lives of 45 years for primary assets and 15 years for secondary assets as defined by Sinclair Knight Merz in its 'Assessment of Economic Lives for Transend Regulatory Asset Classes' report prepared in April 2008 as provided as attachment 24 of Transend's revenue proposal. This document was included as Attachment 24 of Transend's Revenue Proposal. The majority of the primary assets at Palmerston Substation will be 51 years old when decommissioned.

**Figure 2 - Age and value of major 110 kV ($000) assets installed at Palmerston Substation**




# 3 PROJECT TIMING

The project is currently scheduled to commence in 2012 and be completed in 2014.

The timing of this project has been co-ordinated with the prioritised 110 kV circuit breaker replacement program and the overall capital works program. This project is currently ranked ninth of all projects, and fourth of all renewal projects in Transend's works prioritisation tool. The timing of the project has been coordinated with Avoca Substation transformer T2 installation and asset replacements project to minimise the number of outages of the radial Palmerston–Avoca 110 kV transmission line.

It is likely that components of this project may need to be implemented prior to the planned commencement of the project because of the deteriorated condition of certain assets and the fact that additional asset condition issues will most likely be identified prior to commencement of the project. It should be noted that these works, should they be needed, will not result in the need for significant rework because the substation is not being reconfigured.

# 4 INVESTMENT NEED

This project is required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the National Electricity Rules (Rules):

- comply with all applicable regulatory obligations associated with the provision of prescribed transmission services;
- maintain the quality, reliability and security of supply of prescribed transmission services; and
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

The key investment drivers for this project are to address identified safety, condition, and performance issues presented by the primary and secondary assets at Palmerston Substation 110 kV.

## 4.1 CIRCUIT BREAKERS

The 110 kV circuit breakers (11 units) installed at Palmerston Substation are Reyrolle type 110/OS/10 units. The Reyrolle Type 110/OS/10 110 kV Circuit Breaker Condition Assessment Report (TNM-CR-806-0772) recommends that the units at Palmerston Substation be replaced. The circuit breaker condition assessment has been based on key asset management considerations including technical, design, reliability, condition, maintenance, spares and contingency planning, life-cycle and environmental issues. The condition assessment report provides details of the many failures and defects associated with Reyrolle 110 kV circuit breakers, including those installed at Palmerston Substation. The condition assessment report has identified the Reyrolle type 110/OS/10 circuit breakers:

- have a number of inherent technical and design deficiencies that have adversely impacted transmission circuit reliability and availability;
- are unreliable, in particular the air and insulating oil systems;
- are maintenance intensive and costly to maintain when compared with modern equivalent units;
- require spare parts that are no longer available from the manufacturer’s agent;
- require skilled personnel to maintain - the availability of specialised maintenance resources is declining; and
- have reached the end of their useful service lives.

All other transmission companies in Australia and New Zealand have already replaced their population of Reyrolle type 110/OS/10 circuit breaker, or are in the process of doing so, for the same reasons outlined above. Transend’s reasons for replacing this type of circuit breaker are no different to those of other industry participants.

The average preventive maintenance costs associated with the 110 kV circuit breakers at Palmerston Substation include:

- circuit breaker maintenance: $8,300 per circuit breaker (six yearly);
- insulating oil costs: $4,200 per circuit breaker (six yearly);
- compressor maintenance: $1,000 per compressor (six-monthly for the two compressors at Palmerston Substation);
- silica gel maintenance: $500 per circuit breaker (two yearly); and
- pressure inspection costs: $300 per circuit breaker (three yearly).

In addition, the average historic repair cost for a failure or defect associated with a Reyrolle type 110/OS/10 circuit breaker is $4,730.

Further information on the circuit breaker population can also be found in the Extra High Voltage Circuit Breaker Asset Management Plan (TNM-PL-809-0541).

## 4.2 VOLTAGE TRANSFORMERS

The 110 kV voltage transformers at Palmerston Substation comprise the following types:

- ASEA type EMFA120 (six units);
- Ducon type PD-AS-11AB (three capacitor voltage transformer units and one coupling capacitor unit); and
- Reyrolle type KP5323 (one unit).

**ASEA voltage transformers**

The ASEA type EMFA 120 110 kV voltage transformers in service at Palmerston Substation were manufactured in 1963. Voltage transformers of this type have failed explosively in the past. The explosive failure of a voltage transformer presents a significant safety risk to anyone in the vicinity of the voltage transformer at the time of failure. There is also a significant risk of adjacent assets being damaged or destroyed as a consequence of an explosive voltage transformer failure.

The average annual preventive maintenance costs associated with 110 kV voltage transformers at Palmerston Substation are $5,500 per three phase set.

The EHV Voltage Transformer Asset Management Plan (TNM-PL-809-0614) recommends that the ASEA type EMFA 120 110 kV transformers at Palmerston Substation be replaced because they are in poor electrical condition, are susceptible to major failure and are an obsolete design. The ASEA EMFA 120 110 kV voltage transformers will be 51 years old when decommissioned.

**Ducon voltage transformers**

Ducon 110 kV voltage transformers are approaching the end of their service lives, have inherent design deficiencies and are susceptible to explosive failure. Transend has experienced explosive failures of Ducon 110 kV voltage transformers at Palmerston Substation in 2001 and at Avoca Substation in March 2008. Figure 3 presents an image of a failed Ducon 110 kV voltage transformer and porcelain fragments in the switchyard.

**Figure 3 - Explosive failure of a Ducon 110 kV voltage transformer at Avoca Substation**

Ducon voltage transformers that were manufactured prior to 1973 incorporated a unique system where a neoprene rubber gasket was encased within a lead sheath to protect the rubber from the insulating oil. As the units age, the lead sheath becomes susceptible to creeping inward causing lead to fall inside the unit, or the rubber to be exposed to the insulating oil which hardens the rubber and results in deterioration of the oil seal.

The average annual preventive maintenance costs associated with 110 kV voltage transformers at Palmerston Substation is $5,500 per three phase set.

The EHV Voltage Transformer Asset Management Plan (TNM-PL-809-0614) recommends that Ducon voltage transformers at Palmerston Substation be replaced. The Ducon voltage transformers will be 51 years old when decommissioned.

**Reyrolle voltage transformers**

The Reyrolle type KP5323 110 kV voltage transformer at Palmerston Substation was manufactured in 1957 and is the last unit of this type in the transmission network. The EHV Voltage Transformer Asset Management Plan (TNM-PL-809-0614) recommends that the Reyrolle voltage transformer at Palmerston Substation be replaced. The unit will be 57 years old when it is decommissioned.

**Line voltage transformers**

This project includes the installation of voltage transformers on each of the 110 kV transmission lines that connect to Palmerston Substation 110 kV to improve the reliability of electricity supply and to reduce the complexity of the associated transmission line protection schemes. Further details of the line voltage transformer installation program and the units that will be installed at Palmerston Substation 110 kV are provided in the Voltage Transformer Asset Management Plan (TNM-PL-809-00614).

## 4.3 CURRENT TRANSFORMERS

The 110 kV current transformers in service at Palmerston Substation (33 single phase units) are Laur Knudsen type A8ZX units that were manufactured in 1963. A number of these current transformers (as well as units installed elsewhere in the transmission network) have been identified as having high percentage power factor readings. This indicates that it is likely that the insulation has deteriorated and that there may be excessive moisture within the units. The poor condition of a number of these units indicates that they have reached the end of their service life and that they present an increased risk of explosive failure. This type of current transformer utilises a silica gel breather that requires the transmission circuit to be removed from service for maintenance. This deficiency impacts adversely on transmission circuit availability.

The average annual preventive maintenance costs associated with 110 kV current transformers at Palmerston Substation is $5,500 per three phase set.

The Current Transformer Asset Management Plan (TNM-PL-809-0605) recommends that the Laur Knudsen type A8ZX current transformers be progressively replaced with current transformers installed with the dead-tank circuit breakers because they are generally in poor condition and require frequent maintenance in comparison to modern equivalent units. The Laur Knudsen current transformers will be 51 years old when decommissioned.

## 4.4 DISCONNECTORS

The 110 kV disconnectors installed at Palmerston Substation are Stanger type DR2 units. Generally, this type of disconnector has provided reliable service. Given that these disconnectors have proven to be reasonably reliable and are forecast to continue to operate within their current rating, they will be refurbished and retained in service at this time.

The average preventive maintenance costs associated with 110 kV disconnectors at Palmerston Substation is $2,000 per unit.

Details of each disconnector type are provided in the Extra High Voltage Disconnector and Earth Switch Asset Management Plan (TNM-PL-809-0606).

## 4.5 POST INSULATORS

The 110 kV post insulators installed at Palmerston Substation (approximately 225 units) are a multi-piece construction that comprise individual insulators bolted together to achieve the required voltage rating. The multi-piece design post insulators are susceptible to mechanical failure in operating environments such as those at Palmerston Substation, due to moisture freezing within the post insulator, causing the porcelain components to crack. Transend has experienced a significant number of mechanical and electrical failures of multi-piece post insulators over the past 10 years. The consequences of failure have included an increased safety risk to personnel working in switchyards, considerable disruption to electricity supply and the requirement for unplanned outages to facilitate replacement of post insulators.

The Post Insulator Asset Management Plan (TNM-PL-809-0614) recommends the progressive replacement of all multi-piece post insulators.

## 4.6 PROTECTION AND CONTROL

All of the protection and control devices designated to be replaced as part the Palmerston Substation 110 kV redevelopment project are either electromechanical or static types. The EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) details the need to progressively replace obsolete electromechanical or static protection and control devices to sustain the reliability of the transmission network because they:

- are unreliable and maintenance intensive;
- are obsolete technology;
- are no longer supported by their manufacturer;
- do not have self-diagnostic features; and
- require testing and maintenance on a more frequent basis than modern equivalent assets.

The following transmission line distance protection scheme replacements are included in the Palmerston Substation 110 kV redevelopment project.

**Palmerston–Arthurs Lake 110 kV transmission line protection**

The transmission line protection on the Palmerston–Arthurs Lake 110 kV transmission line comprises two static distance protection relays, a GEC Alstom type YTS and a Schulmberger type PDS2000B, both installed in 1977. During routine testing in 2007 the YTS relay was found to be non-operational and required system spare components to repair. After repairs were completed the settings needed to be adjusted to compensate for characteristic drift which caused the relay to over-reach by 20 per cent. Routine testing of the PDS2000B relays has identified that they are deviating from their expected characteristic due to aging components.

**Palmerston–Avoca 110 kV transmission line protection**

The transmission line protection on the Palmerston–Avoca 110 kV transmission line comprises two distance protection relays, an electromechanical Compagne Des Compteurs type RXAP and a static Reyrolle type THR. The RXAP distance relay was installed in 1968. There are six relays of this type currently in service in the transmission network, and of these, three have failed over the past four years. The EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) specifically targets the RXAP relays for replacement due to their poor reliability, slow clearance times and the frequent need for maintenance and repair. The Reyrolle type THR relay was installed in 1984. There are 22 relays of this type in service in the transmission network, of which three have failed over the past four years.

**Palmerston–Hadspen Nos. 3 and 4 110 kV transmission line protection**

The transmission line protection on the Palmerston–Hadspen Nos. 3 and 4 110 kV transmission lines each comprise two static distance protection relays; a Schulmberger type PDS2000B and a Reyrolle type THR, all installed in 1979. Issues associated with both of these relay types are discussed above.

# 5 CUSTOMER CONSULTATION

Transend will liaise directly with relevant stakeholders regarding the intent, scope and implementation of the project as part of the project initiation process.

# 6 BENEFITS

The direct benefits that are achieved through completing the work outlined in the scope of this project will:

- contribute to the achievement of the capital expenditure objectives identified in the Rules;
- provide a safe, secure and reliable electricity supply to customers connected to Palmerston Substation 110 kV by replacing obsolete, unreliable assets that are in poor condition;
- provide life-cycle cost savings due to reduced operations and maintenance requirements;
- reduce the burden on spare parts management by using standard equipment; and
- align with the recommendations made in the respective asset management plans.

# 7 OPTIONS ANALYSIS

The following options have been considered for the redevelopment of Palmerston Substation 110 kV:

1. maintain existing assets and defer replacement;
2. replace selected assets in-situ;
3. staged replacement of selected assets over three years; and
4. completely redevelop Palmerston Substation 110 kV.

Other options considered at a high-level, but discounted include:

- **greenfield development** – this option was clearly not a cost-effective alternative as other solutions can be implemented within the existing perimeter of Palmerston Substation at a substantially lower cost;

- **reconfigure and rationalise the existing 110 kV switchyard –** there are no cost-effective alternatives to reconfigure or rationalise Palmerston Substation 110 kV.

## 7.1 OPTION 1: MAINTAIN EXISTING ASSETS

### 7.1.1 SCOPE

The scope for this option includes:

- replacement of assets that are known to present a significant safety risk, including post insulators, voltage transformers and current transformers in 2014;
- continuation of existing maintenance practices, albeit accelerated due to the declining condition of the assets;
- repairs and corrective maintenance as required; and
- deferred replacement of certain assets by up to five years.

The capital cost of this option includes an initial $4.00 million ($June 2007) to address the identified safety issues, followed by a deferred capital cost of $8.73 million ($June 2007) to replace the remaining 110 kV assets five years later.

### 7.1.2 BENEFITS

The benefits for this option are the deferral of capital expenditure and that the identified safety issues are addressed.

### 7.1.3 DRAWBACKS

The drawbacks for this option are that it would:

- not allow Transend to achieve the capital expenditure objectives;
- not satisfactorily address the performance issues identified in Section 4 of this document;
- not be sustainable given the demonstrated reliability issues associated with the 110 kV primary and secondary assets;
- result in an increased number of loss of electricity supply events at Palmerston Substation when compared with other options;
- incur significantly longer and more frequent outages due to the intensive maintenance regimes that would be required to sustain the existing assets in service (whilst recognising that this approach is almost certainly unlikely to be successful);
- incur increased ongoing operating expenditure due to increased maintenance, condition monitoring and corrective maintenance requirements;
- not align with Transend's policy to utilise dead tank circuit breakers when replacing 110 kV live tank current transformers and circuit breakers; and
- not align with the recommendations made in respective asset management plans for the primary and secondary assets.

### 7.1.4 CONCLUSION

Although this option has lower initial capital cost, it is not the preferred option because it does not ensure the reliable operation of Palmerston Substation 110 kV.

## 7.2 OPTION 2: REPLACE SELECTED ASSETS IN-SITU

### 7.2.1 SCOPE

The scope for this option includes the replacement of the following assets in 2014:

- replacement of assets that are known to present a significant safety risk, including post insulators, voltage transformers and current transformers;

- replacement of the existing live tank circuit breakers with dead tank units that have integral current transformers;
- replacement of the identified protection and control schemes; and
- implementation of revised maintenance practices.

The capital cost of this option is $10.81 million ($June 2007).

#### 7.2.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;
- addresses the safety and performance issues associated with the 110 kV assets as identified in Section 4 of this document;
- defers capital expenditure associated with replacing the 110 kV disconnectors; and
- reduces the maintenance requirements and costs associated with the site.

#### 7.2.3 DRAWBACKS

The option has the following drawbacks:

- higher initial capital cost than option 1.

#### 7.2.4 CONCLUSION

This option is technically viable.

### 7.3 OPTION 3: STAGED REPLACEMENT OF SELECTED ASSETS IN-SITU

#### 7.3.1 SCOPE

The scope for this option is essentially the same as option 2, but implemented using a staged approach based on transmission circuit criticality. This option includes:

- initial replacement of assets that have an assigned transmission circuit criticality rating of four or five (nine bays); and
- initial replacement of other assets that are known to present a safety risk, including post insulators, voltage transformers and current transformers; and
- deferred replacement of the remaining 110 kV assets by up to three years (two bays).

The capital cost of this option includes an initial $9.73 million ($June 2007) to replace critical assets and to address safety issues followed by a deferred capital cost of $1.55 million ($June 2007) to replace remaining 110 kV assets three years later.

#### 7.3.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives in the mid-term;
- addresses the safety issues associated with the 110 kV assets identified in Section 4 of this document;
- defers capital expenditure associated with replacing the 110 kV disconnectors;
- defers capital expenditure associated with lower criticality assets for up to three years;
- addresses the performance issues identified in Section 4 of this document, with the exception of those transmission circuits that have a criticality less than four; and
- reduces the ongoing maintenance requirements and costs associated with the site.

#### 7.3.3 DRAWBACKS

The drawbacks for this option are that it:

- results in a higher initial capital cost than option 1;
- results in a higher overall capital cost than option 2, primarily due to contractor remobilisation and increased internal costs;
- does not align with Transend's policy to utilise dead tank circuit breakers when replacing 110 kV live tank current transformers and circuit breakers for two 110 kV bays;
- reduced efficiencies in project delivery, in particular co-ordination of works associated with the Avoca Substation transformer T2 installation project and asset replacement works; and
- will need additional transmission circuit outages to undertake the works.

#### 7.3.4 CONCLUSION

This option is technically viable.

## 7.4 OPTION 4: COMPLETE REDEVELOPMENT OF PALMERSTON SUBSTATION 110 KV

#### 7.4.1 SCOPE

The scope for this option includes:

- in-situ replacement of the existing live tank circuit breakers with dead tank units that have integral current transformers;
- replacement of 110 kV disconnectors in situ;
- replacement of gantry structures;
- replacement of protection and control schemes; and
- implement revised maintenance practices.

The capital cost of this option is $12.49 million ($June 2007).

#### 7.4.2 BENEFITS

The benefits for this option are that it:

- allows Transend to achieve the capital expenditure objectives;
- addresses safety issues associated with the 110 kV assets identified in Section 4 of this document, in particular the 110 kV voltage transformers and post insulators;
- addresses other performance, reliability and design issues identified in Section 4 of this document;
- improves operational functionality as new 110 kV disconnectors would be motorised and capable of remote operation; and
- reduces the ongoing maintenance requirements and costs associated with the site.

#### 7.4.3 DRAWBACKS

The drawbacks for this option are that it:

- would need outages of an extended duration for each transmission circuit because it would be required to replace 110 kV disconnectors and other infrastructure; and
- would require a higher capital cost than option 2.

#### 7.4.4 CONCLUSION

This option is technically viable.

# 8 OPTION ESTIMATES

A comparison of the net present value of options is provided in Table 1.

**Table 1 - Comparison of options considered**

| | Option | Net present value of costs ($M June 2007) |
|---|---|---|
| 1 | Manage existing assets and defer replacement | -$8.26 |
| 2 | Replace selected assets in-situ | -$8.16 |
| 3 | Staged replacement of selected assets in-situ | -$8.31 |
| 4 | Complete redevelopment of Palmerston Substation 110 kV | -$8.91 |

The economic analysis includes the cost impact to customers in the event of a major circuit breaker failure using a probabilistic approach based on current and forecast load data for each individual transmission circuit connected to Palmerston Substation 110 kV.

# 9 PREFERRED OPTION

Option 2 (replacement of selected assets in-situ) is the preferred option because it is the most cost-effective solution to address the identified safety and performance issues presented by the assets at Palmerston Substation 110 kV. This approach will also minimise the number and duration of transmission circuit outages due to reduced frequency and duration of maintenance.

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | TUNGATINAH SUBSTATION 110 KV REDEVELOPMENT |
| **TRIM REFERENCE** | D09/3754 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 2.0 |
| **TRANSEND CONTACT** | ROD JONES |
| **PROJECT NUMBER** | ND0709 |

## ATTACHMENT A8

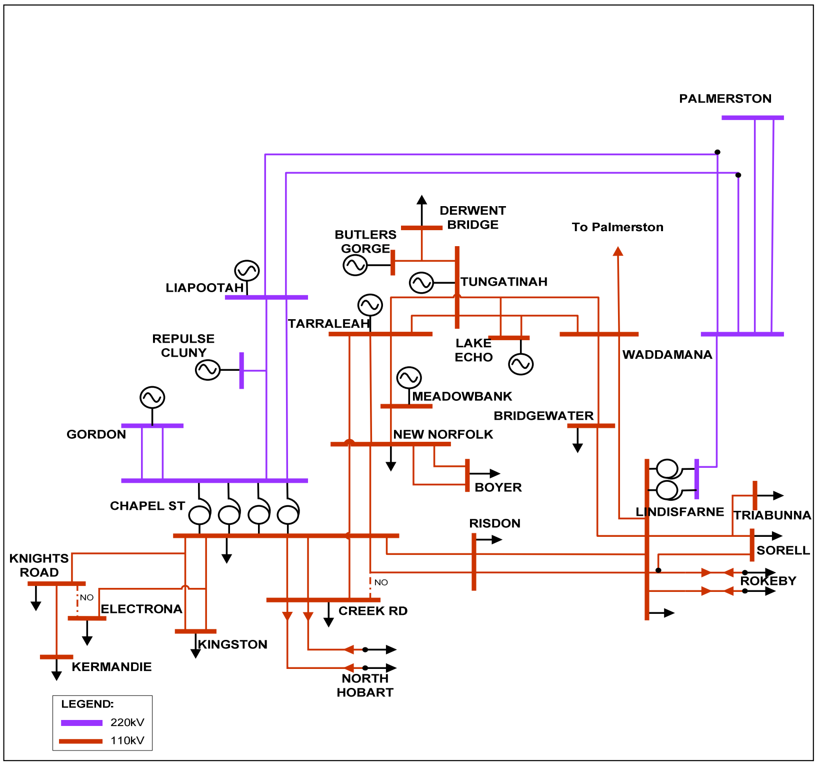
# CONTENTS

# 1 BACKGROUND

Tungatinah Substation and Tarraleah Switching Station are integral parts of the shared 110 kV transmission network in Tasmania. They provide connections to the upper Derwent River and Nive River power stations and to outgoing transmission lines towards the greater Hobart area in the south and to Palmerston Substation in the north of Tasmania.

Tungatinah Substation was commissioned in 1953 and connects to Tungatinah, Butlers Gorge and Lake Echo power stations, and Derwent Bridge, Tarraleah and Waddamana substations. It also provides a 110/22 kV connection for Aurora Energy. Tarraleah Switching Station was commissioned in 1938 and provides 110 kV connections to Tarraleah Power Station and Meadowbank, New Norfolk and Tungatinah substations. In total, the switchyards connect approximately 260 MW of generation to the transmission network. Figure 1 presents the schematic diagram of the southern Tasmanian transmission network that connects Tungatinah Substation and Tarraleah Switching Station.

**Figure 1 – Southern area transmission network schematic diagram**




The vast majority of the primary and secondary assets at Tungatinah Substation and Tarraleah Substation are unsafe and in very poor condition.

Transend undertook an interim circuit breaker replacement program at Tungatinah Substation from 1999 to 2003, replacing the 110 kV air-blast circuit breakers and selected voltage transformers that were susceptible to explosive failure and presented a significant safety risk. Notwithstanding these interim measures, significant safety risks still exist at both Tungatinah Substation and Tarraleah Switching Station.

Transend engaged Ascension Consulting to undertake an independent review of the Tungatinah Substation 110 kV redevelopment project. The independent review identified that:

> *'The condition of the assets at both substations is poor with rusting steelwork, cramped and complex equipment layouts. The switchgear has reached the end of its design life and for good asset management*

*reasons must be replaced. Inadequate safety at both sites in terms of safe working clearances, substandard substation earthing, substation fencing are all strong reasons to undertake the project.*

*Dependence on [third parties] for interfaces for secondary equipment infrastructure is complex and unacceptable in the long-term.*

*This project must achieve a simplification and standardisation of these substations which are both remote and critical to the security of supply of Transend's network.'*

In addition, Ascension Consulting agreed with the approach undertaken with regard to the development of the Tungatinah Substation 110 kV redevelopment project and fully supported the project implementation strategy.

Transend considers that continuing to operate assets that have been independently identified as presenting significant safety risks and being in poor condition is unacceptable.

# 2 PROJECT OVERVIEW

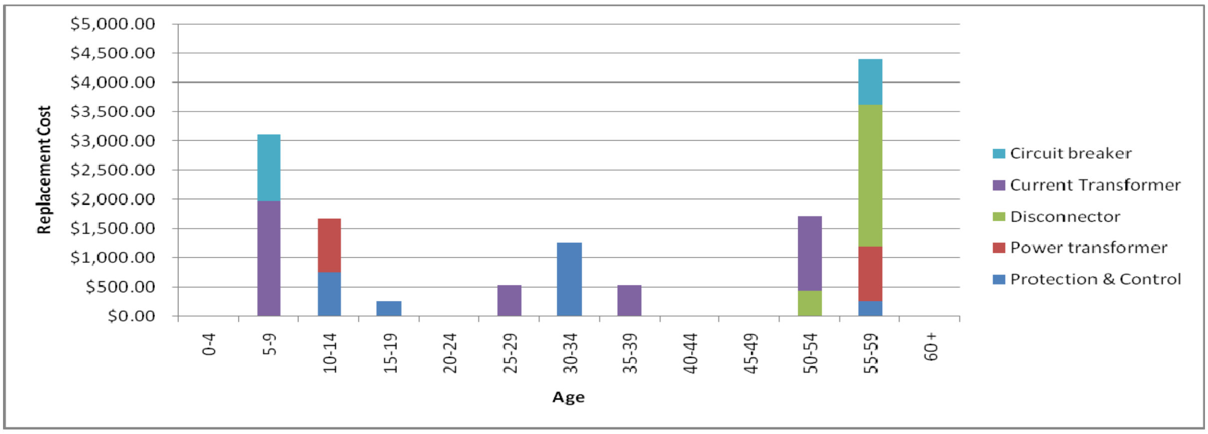
The planned redevelopment and rationalisation of Tungatinah Substation and Tarraleah Switching Station includes the replacement, rationalisation and reconfiguration of all 110 kV primary equipment (including circuit breakers, disconnectors, current and voltage transformers) and replacement of all protection and control equipment. The redevelopment will address significant safety issues at both sites and improve the reliability of electricity supply by replacing assets that are in poor condition and susceptible to failure. The project also includes the reconfiguration of the existing 110 kV ring bus bar arrangements to address operational issues and improve operational flexibility.

Figure 2 presents an image of Tungatinah Substation and Tarraleah Switching Station, which are located on opposite sides of the Nive River, approximately 400 metres apart.

**Figure 2 – Image of existing Tarraleah Switching Station (left) and Tungatinah Substation (right)**

Figure 3 presents a summary of the age of the key 110 kV assets (by category) at Tungatinah Substation and Tarraleah Switching Station by asset replacement cost (note that the scope of this project does not include replacement of the power transformers). Figure 3 clearly illustrates that the majority of the assets included in the Tungatinah Substation 110 kV redevelopment project are well beyond their nominal service lives of 45 years for primary assets and 15 years for secondary assets as defined by Sinclair Knight Merz in its 'Assessment of Economic Lives for Transend Regulatory Asset Classes' report prepared in April 2008 provided as attachment 24 of Transend's revenue proposal. A large proportion of the primary assets at Tungatinah Substation and Tarraleah Switching Station will be at least 63 years old when decommissioned.

**Figure 3 – Summary of age and value ($000) of major 110 kV assets installed at Tungatinah Substation and Tarraleah Switching Station**




# 3 INVESTMENT TIMING

The project is currently scheduled to commence in 2012 and be completed in 2015.

The independent review undertaken by Ascension Consulting recommended that the Tungatinah Substation 110 kV redevelopment project be implemented as soon as practicable. This project has been scheduled to commence as soon as practicable, however it has been deferred primarily because of the need to determine the optimum transmission network configuration. This project has required considerable customer consultation and can only commence once the final stage of the Southern Power System Security program (the Waddamana–Lindisfarne 220 kV transmission line project) is completed.

The Tungatinah Substation 110 kV redevelopment project has been coordinated with the Meadowbank Substation 110 kV redevelopment and New Norfolk Substation 110 kV protection replacements projects to enable new, current differential protection schemes to be installed on the connecting transmission lines, thereby improving the security and reliability of the transmission network in southern Tasmania.

The revised timing of the project has also been co-ordinated with the Creek Road Substation 110 kV redevelopment project given the likely synergies in project implementation methodologies.

The Tungatinah Substation 110 kV redevelopment project is currently the third highest ranking of all proposed projects and the second highest renewal project (ranked closely behind the Creek Road 110 kV redevelopment project) in Transend's works prioritisation tool, primarily because of the safety issues presented by the assets at Tungatinah Substation and Tarraleah Switching Station and the criticality of these sites.

It is possible that some works may need to be implemented prior to the planned commencement of the project because of the deteriorated condition of certain assets and the fact that additional asset condition issues will most likely be identified prior to commencement of the project.

# 4 INVESTMENT NEED

This project is required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the National Electricity Rules (Rules):

- comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
- maintain the quality, reliability and security of supply of prescribed transmission services; and
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

The key investment drivers for this project are to address the significant safety, condition, and performance issues presented by the primary and secondary assets at Tungatinah Substation and Tarraleah Switching Station.

## 4.1 CIRCUIT BREAKERS

### 4.1.1 TARRALEAH SWITCHING STATION

The 110 kV circuit breakers (six units) installed at Tarraleah Switching Station are Reyrolle type 110/OS/10 units. The Reyrolle Type 110/OS/10 110 kV Circuit Breaker Condition Assessment Report (TNM-CR-806-0772) assesses the condition of Reyrolle type 110/OS/10 circuit breakers and recommends that the units at Tarraleah Switching Station be replaced. The circuit breaker assessment has been based on key asset management considerations, including technical, design, reliability, condition, maintenance, spares and contingency planning, life-cycle and environment issues. The condition assessment report has identified that Reyrolle type 110/OS/10 circuit breakers:

- have a number of inherent technical and design deficiencies that have adversely impacted transmission circuit reliability and availability;
- are unreliable, in particular the air and insulating oil systems;
- are maintenance intensive and costly to maintain when compared with modern equivalent units;
- have no spare parts available from the manufacturer’s agent;
- require skilled personnel to maintain - the availability of specialised maintenance resources is declining; and
- have reached the end of their useful service lives.

In addition, the Reyrolle type 110/OS/10 circuit breakers at Tarraleah Switching Station are installed at ground level. Although the circuit breakers are enclosed in chain-mesh fences (that have been installed as an interim safety measure), they still present a safety risk, particularly due to the close proximity of the conductors that connect the circuit breakers.

All other transmission companies in Australia and New Zealand have already replaced their population of Reyrolle type 110/OS/10 circuit breakers, or are in the process of doing so, for the same reasons outlined above. Transend’s reasons for replacing this type of circuit breaker are no different to those of other industry participants.

The preventive maintenance costs associated with the 110 kV circuit breakers at Tarraleah Switching Station include:

- circuit breaker maintenance: $9,500 per circuit breaker (six yearly);
- insulating oil costs: $4,200 per circuit breaker (six yearly);
- compressor maintenance: $1,000 per compressor (six-monthly for the compressor at Tarraleah Switching Station);
- silica gel maintenance: $500 per circuit breaker (two yearly); and
- pressure inspection costs: $300 per circuit breaker (three yearly).

In addition, the average historic repair cost for a failure or defect associated with a Reyrolle type 110/OS/10 circuit breaker is $4,730.

Further information on the circuit breaker population can also be found in the Extra High Voltage Circuit Breaker Asset Management Plan (TNM-PL-809-0541).

### 4.1.2 TUNGATINAH SUBSTATION

From 1999 to 2003, Transend replaced six English Electric 110 kV air-blast circuit breakers that presented a significant safety risk because they were susceptible to explosive failure. The circuit breakers were only installed temporarily using available spare units because of the impending substation redevelopment project. One of the explosive failures that occurred at Tungatinah Substation caused a statewide blackout in 1979.

The 110 kV circuit breakers installed at Tungatinah Substation include the following types:

- ABB type LTB145D1 - one unit (age 13 years);
- Mitsubishi 100-SFMT-40E - six units (average age 11 years); and
- Siemens 3AP1DT - two units (average age 9 years).

The circuit breakers currently in service at Tungatinah Substation will be redeployed elsewhere in the transmission network.

## 4.2 DISCONNECTORS AND EARTH SWITCHES

### 4.2.1 ASSET CONDITION

The 110 kV disconnectors installed at Tarraleah Switching Station and Tungatinah Substation comprise the following types:

- Acelec types 06732 and HDBE;
  - Tarraleah - three units (average age of 58 years); and
  - Tungatinah - two units (average age of 55 years).
- Essantee types 05533, 05551, 05552 and 09279
  - Tarraleah - 11 units (average age of 58 years); and
  - Tungatinah - 14 units (average age of 56 years).

The average maintenance costs associated with the 110 kV disconnectors at Tarraleah Switching Station and Tungatinah Substation are $3,000 per disconnector.

Details of each disconnector type can also be found in the Extra High Voltage Disconnector and Earth Switch Asset Management Plan (TNM-PL-809-0606).

**Acelec disconnectors**

The Acelec disconnectors are in very poor condition and are susceptible to thermal failure of the conductive braids. This type of disconnector is difficult to maintain due to a complex fixed contact arrangement. In addition, a number of disconnectors are mounted on girders and/or underhung approximately 10 metres above ground level, requiring additional resources to maintain.

Any spares required to sustain this type of disconnector in service needs to be locally manufactured or salvaged from decommissioned units.

In the past, a serious safety incident occurred at Tarraleah Switching Station when a post insulator associated with a girder-mounted 110 kV disconnector mechanically failed while it was being operated. The failure resulted in parts of the disconnector falling to the ground and narrowly missing the Field Operator who was operating the device.

The Acelec type 06732 disconnectors are designed for operation at 88 kV and do not provide the required electrical clearances for compliant operation at 110 kV.

**Essantee disconnectors**

The Essantee disconnectors are in very poor condition and need to be replaced. The units are susceptible to thermal failure of the conductive braids. The disconnectors have also experienced failures of the operating linkage, preventing the disconnector from operating; seizing of pivot joints, preventing contacts and disconnector from closing; and contact misalignment due to weakened springs and worn pivot joint assemblies.

The Essantee disconnectors are designed for operation at 88 kV and do not provide the required electrical clearances for compliant operation at 110 kV.

### 4.2.2 TRANSMISSION LINE DISCONNECTORS AND EARTH SWITCH INSTALLATION PROGRAM

The Extra High Voltage Disconnector and Earth Switch Asset Management Plan (TNM-PL-809-0606) recommends the installation of disconnectors and earth switches on five transmission circuits at Tungatinah Substation that currently do not have line-side disconnectors and earth switches installed. The circuits include:

- Tungatinah–Lake Echo–Waddamana No. 1 110 kV transmission line;
- Tungatinah–Lake Echo–Waddamana No. 2 110 kV transmission line;
- Tarraleah–Tungatinah No. 1 110 kV transmission line;
- Tarraleah–Tungatinah No. 2 110 kV transmission line; and
- Tungatinah–Butlers Gorge–Derwent Bridge 110 kV transmission line.

In addition, the plan recommends the installation of five earth switches on 110 kV disconnectors at Tarraleah Substation including disconnectors B129B, C129B, D129B, E129B and F129B.

## 4.3 VOLTAGE TRANSFORMERS

### 4.3.1 TARRALEAH SWITCHING STATION

The 110 kV voltage transformers installed at Tarraleah Switching Station comprise the following types:

- Balteau type UEV110 - three units (average age of 31 years);
- Brown Boveri TMZF - three units (72 years);
- Ritz OTEF 123 - three units (10 years);
- Tyree 05/110/4 - three units (33 years); and
- Tyree 05/123/5 - six units (30 years).

The Balteau 110 kV voltage transformers are of an obsolete design and are in poor electrical condition. They have high percentage power factor readings, which indicate excessive moisture in the insulating oil and likely degradation of the winding insulation. While Transend has not experienced any major failures of Balteau voltage transformers, other Australian transmission companies have reported explosive failures of Balteau voltage transformers of a similar design. The explosive failure of a voltage transformer presents a major safety risk to anyone in the vicinity of the voltage transformer at the time of failure.

The Extra High Voltage Voltage Transformer Asset Management Plan TNM-PL-806- 0614)also recommends the replacement of Brown Boveri type TMZF 110 kV voltage transformers. Brown Boveri TMZF voltage transformers have a number of design issues, including:

- the electrical condition can not be assessed by electrical testing as the primary winding of the units is earthed internally;
- the use of a free-to-air vent, which exposes the insulating oil to moisture ingress; and
- the units are installed at ground level, which presents safety issues associated with substandard electrical clearances.

The Ritz and Tyree voltage transformers installed at Tarraleah Switching Station will be redeployed elsewhere in the transmission network.

The average maintenance costs associated with 110 kV voltage transformers is $1,250 per three phase set.

#### 4.3.2 TUNGATINAH SUBSTATION

The 110 kV voltage transformers installed at Tungatinah Substation include the following types:

- Haefely Trench VEOT 123 - three units (average age of 22 years);
- Ritz OTEF 123 - seven units (12 years); and
- Trench SVS 123/3 - six units (9 years).

Between 1999 and 2003, a number of 110 kV voltage transformers (Brown Boveri TMZF and Asea Type EMFA) that were in extremely poor condition were replaced to eliminate the likelihood of explosive failure and to sustain the performance of the substation prior to the redevelopment of Tungatinah Substation 110 kV. The replacement units were manufactured by Trench and are in acceptable condition. The Trench voltage transformers installed at Tungatinah Substation will be redeployed elsewhere in the transmission network.

The average preventive maintenance costs associated with 110 kV voltage transformers at Tungatinah Substation is $1,250 per three phase set.

Voltage transformers installed at Tungatinah Substation will be re-used in the redevelopment project or redeployed elsewhere in the transmission system.

### 4.4 CURRENT TRANSFORMERS

The 110 kV current transformers installed at Tarraleah Switching Station comprise the following types:

- ABB type 236080 - nine units (average age of 13 years);
- Endurance Electric type OD-01-WP - six units (39 years); and
- Tyree type 06/123/16 - six units (30 years).

The 110 kV post type current transformers installed at Tungatinah Substation include three ABB type 236080 units (average age of nine years).

In 1996, a number of Reyrolle 110 kV current transformers that were contaminated with polychlorinated biphenyl (PCB) and in poor condition were replaced to ensure compliance with environmental legislation and to sustain the performance of the substation. ABB type 236080 units were installed in place of the Reyrolle units.

The current transformers will be assessed for their suitability for redeployment elsewhere in the transmission network or retained as spares.

The average preventive maintenance costs associated with 110 kV current transformers is $1,250 per three phase set.

### 4.5 POST INSULATORS

The 110 kV post insulators installed at Tungatinah Substation and Tarraleah Switching Station include:

- P640 units - 279 units installed at Tungatinah Substation; and
- P701A - 117 units installed at Tarraleah Substation.

The post insulators are a multi-piece construction that comprise individual insulators bolted together to achieve the required voltage rating. The multi-piece design post insulators are susceptible to mechanical failure in certain operating environments, such as those at Tungatinah Substation and Tarraleah Switching Station due to moisture freezing within the post insulator, causing the porcelain components to crack. Transend has experienced a significant number of mechanical and electrical failures of multi-piece post insulators over the past 10 years. The consequences of failure have included an increased safety risk to personnel working in switchyards, considerable disruption to electricity supply and the requirement for unplanned outages to facilitate replacement of post insulators.

The post insulator asset management plan (TNM-PL-809-0614) recommends the progressive replacement of multi-piece post insulators.

## 4.6 BUS CONDUCTOR AND FITTINGS

The 110 kV bus conductors at Tungatinah Substation and Tarraleah Switching Station are constructed from dual 19/.092 hard drawn stranded copper conductor and 32 mm x 10 gauge copper bar, which is not a standard size and requires custom fittings. In addition, the conductor and fittings are insufficiently rated for any unforseen increase in loading levels at either site.

The 110 kV conductor fittings utilise bolted type fittings throughout the switchyards. Bolted terminal clamps are an obsolete technology that have inherent design issues that can result in the loosening of bolts over time. The loosening of the conductor fitting can lead to high resistance joints. Contemporary practice is to use compression type fittings mitigate the risks associated with bolted fittings.

## 4.7 PROTECTION AND CONTROL SYSTEMS

The vast majority of the protection and control devices that will be replaced as part the Tungatinah Substation 110 kV redevelopment project are either electromechanical or static types. The EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) details the need to progressively replace obsolete electromechanical or static protection and control devices to sustain the reliability of the transmission network because they:

- are unreliable and maintenance intensive;
- are obsolete technology;
- are no longer supported by their manufacturer;
- do not have self-diagnostic features; and
- require testing and maintenance on a more frequent basis than modern equivalent assets.

The average preventive maintenance costs associated with the protection and control systems that are scheduled for replacement at Tungatinah Substation and Tarraleah Switching Station include:

- transmission circuit schemes: $4,200 per scheme (three yearly for static devices); and
- 110 kV bus-zone schemes: $11,250 (three yearly for static devices).

The following transmission line distance protection scheme replacements are included in the Tungatinah Substation 110 kV redevelopment project.

**Tungatinah–Butlers Gorge–Derwent Bridge transmission line protection scheme**

The transmission line protection on the Tungatinah–Butlers Gorge–Derwent Bridge 110 kV transmission lines comprises one GEC type PYTS static distance protection relay and one Schlumberger type PDS2000B distance protection relay. Both distance protection relays were installed in 1977.

There are eight PYTS relays currently in service in the transmission network, and of these, two have failed over the past five years.

There are 13 PDS2000B relays currently in service in the transmission network, and of these, one has failed over the past five years.

**Tarraleah–Meadowbank 110 kV transmission line protection scheme**

The transmission line protection on the Tarraleah–Meadowbank 110 kV transmission line comprises one GEC type PYTS static distance protection relay and one Schlumberger PDS2000B distance protection relay. Both distance protection relays were installed in 1979. Issues associated with the types of distance protection relay are discussed above.

**Tarraleah–New Norfolk No. 1 110 kV transmission line protection scheme**

The transmission line protection on the Tarraleah–New Norfolk No. 1 110 kV transmission line comprises one Mitsubishi type MDT-B151 static distance protection relay and one Schlumberger PDS2000B static distance protection relay. Both distance protection relays were installed in 1980. Issues associated with the PDS2000B distance protection relay are discussed above.

There are eight MDT-B151 relays currently in service in the transmission network, and of these, three have failed over the past five years.

**Tarraleah–New Norfolk No. 2 110 kV transmission line protection scheme**

The transmission line protection on the Tarraleah–New Norfolk No. 2 110 kV transmission line comprises one GEC type PYTS static distance protection relay and one Schlumberger PDS2000B static distance protection relay. Both distance protection relays were installed in 1980. Issues associated with these protection relays are discussed above.

## 4.8 SWITCHYARD LAYOUTS

The Tungatinah Substation 110 kV switchyard is a ring bus arrangement. This arrangement, as applied at Tungatinah Substation, presents significant operational issues, mainly because all transmission line and generator circuits and loads are connected to single points on the 110 kV bus bar. In 2005, the bypass bus bar was decommissioned by the Generator connected to the substation. This has caused a significant reduction in operational flexibility particularly when the removal of critical assets from service is required for maintenance or repair. Extensive planning and transmission network reconfiguration is required to enable the assets to be removed from service.

The 110 kV switchyard arrangement at Tarraleah Switching Station was originally a ring bus arrangement, but was temporarily reconfigured in 1996 with a number of circuit breakers that formed the ring bus removed, resulting in the removal of the ring bus. The current arrangement is essentially two bus bars with a single bus coupler. The current arrangement is not configured such that transmission line or generator circuits can be transferred to the alternate 110 kV bus bar. This arrangement requires multiple transmission lines and a major generator connection to be removed from service when the 110 kV bus bars are required to be removed from service for maintenance or repair. Extensive planning and transmission network reconfiguration is required to enable the assets to be removed from service.

The redevelopment of Tungatinah Substation and Tarraleah Switching Station provides the opportunity to cost-effectively reconfigure and rationalise the 110 kV bus bars to provide improved reliability, availability and operational flexibility. Each transmission circuit and load will have the ability to connect to multiple points on the 110 kV bus bar, which will enable critical assets to be removed from service with a minimal impact on the transmission network.

## 4.9 TRANSMISSION LINE SUBSTANDARD CLEARANCES

The two transmission lines between Tarraleah and Tungatinah switchyards have substandard conductor to ground clearances. The substandard clearances present public safety risks and do not comply with industry standards and guidelines. While Transend is close to completing a program to eliminate substandard conductor to ground clearances, works to address the issues associated with the Tarraleah–Tungatinah No. 1 and No. 2 110 kV transmission lines have been deferred so that the works can be cost-effectively co-ordinated with the Tungatinah Substation redevelopment project.

The Tarraleah–Tungatinah No. 1 and No. 2 110 kV transmission lines constrain the operation of the transmission system during hot weather and with significant generation in the upper Derwent area. The constraint in noted in the Transend 2008 Annual Planning Report (page 86). The Tungatinah Substation redevelopment project provides the opportunity to cost-effectively remove this constraint.

## 4.10 BOYER TEE STRUCTURE

Boyer Tee Structure was constructed in 1941 to support and transpose the overhead conductors of the transmission lines emanating from Tarraleah Switching Station and Meadowbank Substation. A safety audit performed in December 2003 identified inadequate electrical clearances associated with the 110 kV transmission circuits. The substandard clearances present a significant safety risk to personnel or unauthorised persons who enter the tee structure because energised equipment are within reach while standing at ground level. In addition, maintenance activities undertaken at Boyer Tee

Structure site require special attention to ensure that electrical clearances are maintained and that the correct transmission circuits are identified. Transend has implemented a number of interim measures, including improved security fencing, the installation of barriers and additional signage. However, these interim measures are not acceptable for the long term.

The redevelopment of Tungatinah Substation and Tarraleah Switching Station provides the opportunity to cost-effectively remove the transmission gantry structures that comprise the tee structure and over-pass the Boyer Tee Structure site. The removal of the gantry structures will eliminate the significant safety risks associated with the grossly substandard electrical clearances at Boyer Tee Structure.

# 5 CUSTOMER CONSULTATION

Over the past few years extensive consultation has been undertaken with affected customers with respect to the proposed 110 kV redevelopment of Tungatinah Substation.

Transend proposes to purchase additional land to allow the preferred substation configuration to be achieved. Transend has compulsory acquisition powers, which will be used if there are issues with the preferred option of purchasing land by agreement. Given the long lead time before work is to commence, Transend is confident that all customer and acquisition issues associated with this project will be resolved, allowing the project to proceed in the timeframe forecast in the revenue proposal.

# 6 BENEFITS

The direct benefits of redeveloping Tungatinah Substation and Tarraleah Switching Station include:

- the major safety risks associated with 110 kV assets and the grossly substandard electrical clearances will be addressed;
- increased reliability and availability of electricity supply by replacing obsolete, unreliable assets that are in poor condition;
- increased operational flexibility, with a reduced need to reconfigure the 110 kV transmission network;
- direct operational cost savings due to reduced maintenance costs by replacing high maintenance equipment with new, modern and low maintenance equipment;
- reduced spares inventory; and
- alignment with strategic asset management plans.

# 7 OPTIONS ANALYSIS

## 7.1 PRELIMINARY OPTIONS ANALYSIS SUMMARY

An initial review of options to redevelop Tungatinah Substation and Tarraleah Switching Station was undertaken by Sinclair Knight Merz in 2005 (refer to SKM's interim report TRIM D05/2848). The options considered include:

1. upgrade the two stations on their existing sites;
2. rationalise both stations at Tungatinah Substation;
3. rationalise both stations on a greenfield site;
4. upgrade Tungatinah Substation on the existing site and replace Tarraleah Switching Station at a greenfield site.

Sub-options recognised the following factors:

- the possibility of cable interconnection between the two existing stations;
- the possible use of GIS to overcome space limitations;
- the possibility of a distribution system back-up to a single 110/22 kV transformer supply of Aurora Energy;

- the possibility of a 220 kV connection to Tarraleah Switching Station.

### 7.2 DETAILED OPTIONS ANALYSIS

The following options for redeveloping Tarraleah and Tungatinah switchyards were investigated in detail by SKM in their final report:

- Option 1: upgrade of both Tarraleah and Tungatinah switchyards in-situ using air-insulated switchgear (AIS);
- Option 2a: consolidate at Tungatinah Substation with fully selectable double bus AIS;
- Option 2c: consolidate at Tungatinah Substation with double bus AIS and back-to-back connections;
- Option 3b: remote site using gas-insulated switchgear (GIS); and
- Option 3c: remote site using hybrid switchgear.

Refer to the final report for full details of each option.

## 8 OPTION ESTIMATES

SKM provided detailed cost estimates for each option in its final report . Based on Transend's experience, the procurement and installation costs used by SKM to build cost estimates for each option are significantly lower than the actual costs Transend has incurred on recent projects. An independent review of the options for the project stated that:

> *'The SKM work was a standard approach for options evaluation. It is not practical in that type of study to look in depth at all options and the entire project scope. Additional work required in this project is at the remote ends of lines and the very practical issues of how to construct the preferred solution. That work was done in the next phase (in-house) and went beyond SKM's scope.*
>
> *Although the Brownfield solution may be possible at Tungatinah, the SKM study was not required to investigate all costs involved, such as obtaining outages on equipment including the time and disruption to both generation and to transmission that would be required.'*

The report states that a brownfield redevelopment typically adds 20 to 40 per cent premium to the total project cost.

A summary of SKM's original cost estimates is detailed in Table 1. The table also provides a summary of the economic analysis of each option (with and without the application of a brownfield factor applied to the capital cost of the redevelopments).

**Table 1 – Cost comparison of options considered**

| Option | | SKM estimated capital cost of option ($2005 million) | Net present value of option ($2007 million) excluding Brownfield factor | Net present value of option ($2007 million) including 20 percent Brownfield factor |
|---|---|---|---|---|
| 1 | Upgrade of both Tarraleah and Tungatinah switchyards in-situ | $11.31 | -$15.45 | -$18.18 |
| 2a | Consolidate at Tungatinah with fully selectable double bus AIS | $11.62 | -$16.17 | -$18.97 |
| 2c | Consolidate at Tungatinah with double bus AIS and back-to-back connections | $11.15 | -$15.26 | -$17.95 |
| 3b | Remote site using gas-insulated switchgear (GIS) | $14.11 | -$17.89 | -$17.89 |
| 3c | Remote site using hybrid switchgear | $12.97 | -$16.50 | -$16.50 |

On the basis that SKM identified an AIS solution as the lowest capital cost option, Transend prepared a detailed scope and estimate for this option. Details of the scope are provided in document 'Tungatinah Substation 110 kV redevelopment – project definition form' (TRIM D08/20858). At a high level, the basis for the estimate includes the following key activities:

- redevelop Tungatinah Substation 110 kV switchyard by:
    - replacing the remaining switchgear, conductors and string-insulator assemblies of obsolete design and manufacture (ie. re-use recently replaced equipment where practicable);
    - replacing and relocating all protection and control schemes to improve functional performance;
    - rationalise switching arrangements by removing the ring bus; and
    - segregating transmission assets from their existing location in the power station to provide independent SCADA and DC supplies, together with security against fire, flood and intruders.
- redevelop Tarraleah Switching Station 110 kV switchyard by:
    - replacing all switchgear, conductors and string-insulator assemblies of obsolete design and manufacture;
    - replacing and relocating all protection and control schemes to improve functional performance;
    - rationalising equipment by relocating identified switch-bays to Tungatinah; and
    - segregating transmission assets from the power station location to provide independent SCADA and DC supplies, together with security against fire, flood and intruders.
- removal of sub-standard transmission line clearances by:
    - ground profiling/replacement of structures on TL424 (TA–TU, west); and
    - removing the Boyer Tee Structure and over-passing the Boyer Tee Structure site.
- rationalise switching arrangements to improve constructability, operability (protection and network performance) and maintainability; and
- consolidate Transend's protection and control assets at a new control building at Tungatinah Substation.

A summary of the various components of Transend's estimates is provided in Table 2.

**Table 2 – Summary of Transend's cost estimates for various components of option 1**

| Component of estimate | Estimated capital cost ($2007 million) |
|---|---|
| Tungatinah 110 kV switchyard redevelopment – AIS | $12.46 |
| Tarraleah–Tungatinah Nos. 1 and No. 2 110 kV T/L substandard clearances | $0.56 |
| Boyer Tee Structure over-pass | $0.82 |
| Tarraleah 110 kV switchyard redevelopment – AIS | $6.92 |
| Easement and land costs | $0.57 |
| **TOTAL** | **$21.33** |

# 9 PREFERRED OPTION

Options 1, 3b and 3c are acceptable options.

The drawbacks with options 2a and 2b (consolidated AIS options at Tungatinah Substation) include:

- the double-bus bar option would be difficult to achieve given the site constraints and outage management issues;
- significant reconfiguration of transmission line circuits is required; and
- both options present increased risks during implementation working within a constrained, energised site.

Option 3c (remote site using hybrid switchgear) is technically feasible, however it may present a technology risk as Transend has not previously utilised hybrid switchgear in its transmission network.

Given the constraints and numerous construction methodologies that may be implemented, Transend intends to issue this project as a design and construct package to achieve the best economic outcome. The project documentation will leave it open to tenderers to submit arrangements that may include AIS, GIS or hybrid switchgear solutions.

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | FARRELL SUBSTATION 110 KV AND 220 KV BUS BAR PROTECTION SCHEME REPLACEMENTS |
| **TRIM REFERENCE** | D09/3822 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 2.0 |
| **TRANSEND CONTACT** | TREVOR SCOTT |
| **PROJECT NUMBER** | ND0914 |

## ATTACHMENT B1

# CONTENTS

# 1 BACKGROUND

Farrell Substation was established in 1982 to provide a connection point for the Pieman River power development and is a critical node in the Tasmanian transmission network. It connects up to 618 MW of generation to the Tasmanian power system and, in turn, the national electricity grid via Basslink. Under certain generation scenarios, Farrell Substation can transmit up to one third of Tasmania's generation requirement. In addition, the substation is critical to providing a secure and reliable electricity supply to customers located on the west coast of Tasmania. The load supplied from Farrell Substation is predominantly for mining and minerals processing and in 2007 the maximum demand was approximately 70 MW.

Farrell Substation is located on Tasmania's remote west coast and is frequently exposed to inclement weather conditions. On a number of occasions each year, the substation can not be accessed by road because of snow and ice. In addition, the substation is approximately two hours drive from the nearest fault response centre. Therefore, adequate remote control and monitoring facilities are essential to ensuring the security, reliability and availability of the transmission network.

The two existing bus bar protection schemes (one each on the 220 kV and 110 kV) were commissioned in 1983 as part of the original substation development. The protection relays are now 25 years old and are well beyond their nominal service life of 15 years. They are Brown Boveri type INX2 static low impedance schemes and are the only bus bar protection schemes of this type in Transend's transmission network.

# 2 PROJECT OVERVIEW

This project comprises the replacement of the 220 kV and 110 kV bus bar protection schemes at Farrell Substation. The bus bar protection schemes will be replaced with new duplicate schemes on both the 110 kV and 220 kV bus bars.

The new bus bar protection schemes will be installed in the existing relay room at Farrell Substation. New multi-core cabling will be required within the relay room to connect the new panels to Current Transformer, trip, control, AC/DC supplies, disconnector imaging and SCADA circuits. The project also includes the installation of a small quantity of cabling from the switchyard to the control building, but it does not include provision for new multi-core cabling between assets located in the switchyard. Preliminary investigations indicate that there is sufficient spare capacity in the existing multi-core cabling to accommodate the requirement for additional signalling from the primary plant. It may be a requirement to utilise or install auxiliary relays if detailed designs identify that there are insufficient spare cable cores.

The 220 kV bus bar protection scheme will need to accommodate ten substation bays: A4 (transformer T1), B4 (transformer T2), H1 (Sheffield–Farrell No. 1 transmission line), J1 (Sheffield–Farrell 220 kV No. 2 transmission line) , D1 (Farrell–Reece No. 1 transmission line), E1 (Farrell–Reece No. 2 transmission line), A1 (Farrell–Tribute transmission line), B1 (Farrell–John Butters transmission line), (Farrell–Bastyan transmission line), and A7 (bus coupler bay).

The 110 kV bus bar protection scheme will need to accommodate seven substation bays: A5 (transformer T1), B5 (transformer T2), N1 (Farrell–Que-Savage River–Hampshire transmission line), S1 (Farrell–Rosebery transmission line), T1 (Farrell–Rosebery–Queenstown transmission line), P1 (Farrell–Mackintosh transmission line) and B7 (bus coupler bay).

# 3. INVESTMENT TIMING

The Farrell Substation bus bar protection replacement project has been programmed to commence in early 2009, with final commissioning in June 2010. The project has been attributed a high priority because of the high likelihood and impact of critical protection scheme failures.

NPV analysis demonstrates that it is most efficient to start this project in 2009.

The 110 kV bus zone has proven more unreliable than the 220 kV system, so it is proposed to undertake works on this system first. The project is proposed to be staged as follows:

1. Commission the new 110 kV Bus Zone Protection B scheme (GE Multilin type B90), maintaining the existing Brown Boveri type INX2 scheme in service. Use the existing spare protection CT of bays for new bus bar protection scheme

2. Commission the new 220 kV Bus Zone Protection B scheme (GE Multilin type B90), maintaining the existing Brown Boveri type INX2 scheme, de-commissioning the back up high impedance scheme in order to be able to provide CT for new scheme.
3. Commission the new 110 kV Bus Zone Protection A Scheme (Areva P740), de-commission the existing Brown Boveri type INX2 scheme.
4. Commission the new 220 kV Bus Zone Protection A Scheme (Areva P740), de-commission the existing Brown Boveri type INX2 scheme.

# 3 INVESTMENT NEED

## 3.1 RELIABILITY

Each of the bus bar protection schemes at Farrell Substation (110 kV and 220 kV) has recently suffered failures due to deteriorating components. A summary of the bus bar protection scheme failures at Farrell Substation is presented in Figure 1 and **Error! Reference source not found.**. These failures have resulted in extended protection scheme outages. The existing bus bar protection schemes have an auto-test function that operates once per week. If the equipment fails its auto-test then the protection scheme is blocked from operation. Given the auto-test only operates once per week, then the average protection scheme outage would be 3.5 days. An allowance of around 20 hours for repair then the total (average) protection scheme outage time would be approximately be 4.5 days.

The failure rates for the bus bar protection schemes at Farrell Substation are increasing as the condition of the components continue to deteriorate. The components of these systems fail randomly and they can not be predicted. Figure 1 and Table 1 shows that as a whole the protection schemes are failing more often and are becoming more unreliable over time.

**Figure 1 – Bus bar protection scheme failures at Farrell Substation**

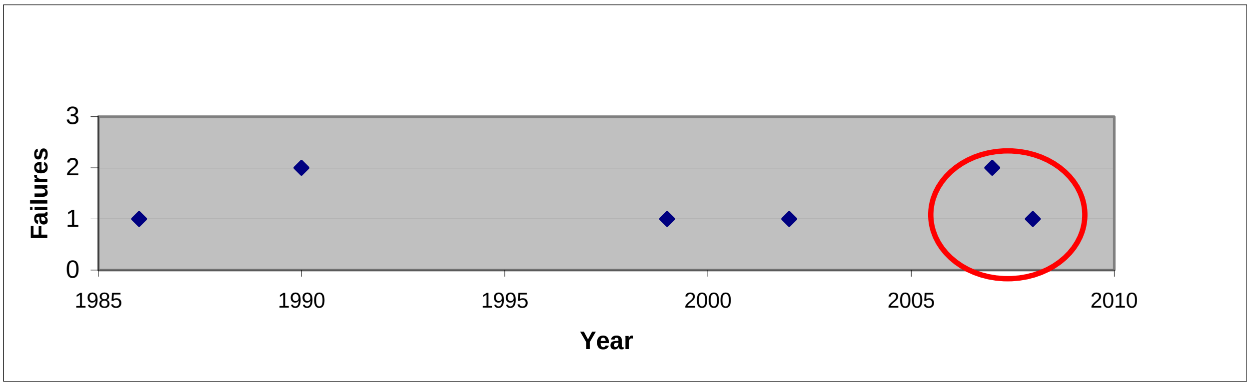



**Table 1 – Bus bar protection scheme failures at Farrell Substation**

| Date | Scheme | Outage duration of Protection scheme (estimated average) | Description of Failure |
|---|---|---|---|
| 30/9/2008 | 110 kV | 4.5 days | 110 kV bus bar protection scheme failed auto-test. Output reed relays on modules MCT425A and BLR429 replaced. |

| Date | Scheme | Outage duration of Protection scheme (estimated average) | Description of Failure |
|---|---|---|---|
| 9/10/2007 | 220 kV | 4.5 days | 220 kV bus bar protection scheme failed auto-test. Failed HST491-C card replaced. |
| 13/08/2007 | 110 kV | 4.5 days | Bus bar protection scheme failed auto-test. One system module was defective due to a faulty reed switch. Lack of spares prevented a direct module replacement consequently the reed switch was repaired. |
| 14/1/2002 | 110 kV | 4.5 days (assuming that auto test detected the problem | Faulty power supply replaced. |
| 18/6/1999 | 220 kV | 4.5 days | Auto-test failed. Broken wiring loop found on back of MCT418 module. |
| 26/12/1990 | 220 kV | 4.5 days | Auto-test failed. Faulty HDT434 white phase card replaced. |
| 15/2/1990 | 220 kV | 4.5 days | Auto-test failed. Faulty HDT434 red phase card replaced. |
| 14/1/1986 | 110 kV | 4.5 days | Auto-test failed. Faulty BDR460 and HST491 replaced. |

## 3.2 IMPACT OF BUS BAR PROTECTION SCHEME OUTAGES

The transmission line distance protection schemes installed at substations that connect to Farrell Substation are relied upon to clear bus bar faults when either of the existing single bus bar protection schemes are out of service. These distance protection schemes are set to clear a bus bar fault in under 0.5 seconds in the event of the bus bar protection scheme being inoperable or out-of-service. However there is no guarantee that the remote distance protection relays will detect a fault within the required timeframe. Distance protection schemes may not see remote bus bar faults due to the effects of zero sequence mutual impedances between parallel transmission lines and in-feeding from connected circuits. Distance protection schemes also have limited capability to see high impedance faults due to the need to cater for normal system load impedance.

The potential impact and risk mitigating measures that need to be put in place in the event of a 220 kV or 110 kV bus bar protection scheme outage at Farrell Substation is discussed below.

### 3.2.1 220 kV BUS BAR PROTECTION SCHEME

The 'Assessment of Farrell 220 kV Bus A and B zone Protection Outages' document recommends that the following limits be put in place in the event of a 220 kV bus bar protection scheme outage at Farrell Substation:

*'It is recommended that during a primary protection outage at Farrell, Mackintosh be constrained to operate below 50% of its maximum output, and that all other West Coast machines be constrained to operate at below 70% of their maximum output. This should allow for a suitable margin of safety, without over-constraining the output of West Coast machines.'*

Given the above, approximately 150 MW of generation could be constrained at Farrell Substation in the event of a 220 kV bus bar protection outage in order to maintain system stability after a short circuit fault.

#### 3.2.2 110 KV BUS BAR PROTECTION SCHEME

The ‘Assessment of Farrell 110 kV bus zone protection outage’ document recommends that the 110 kV bus coupler circuit breaker be opened and that the Farrell–Que–Savage River–Hampshire 110 kV transmission line be transferred to ‘A’ bus bar, or alternatively the 110 kV bus coupler circuit breaker be opened and Mackintosh Power Station (approximately 80 MW of generation capacity) be constrained off in the event of a 110 kV bus bar protection scheme outage at Farrell Substation.

### 3.3 ASSET MAINTAINABILITY

Recent failures of the bus bar protection schemes at Farrell Substation have depleted the spares stocks that were previously held to support the Brown Boveri type INX2 bus bar protection schemes. Spare parts for this type of equipment are no longer available from the manufacturer. Consequently, it is likely that in the event of a bus bar protection scheme failure, the faulted equipment will not be able to be repaired. A permanent failure of either bus bar protection scheme at Farrell Substation would require the installation of a completely new bus bar protection scheme. The replacement of a bus bar protection scheme can not be practically achieved within the time frame of 16 hours as designated by NEMMCO in its operating procedure.

A modern bus bar protection scheme is formed by the assembly of a number of discrete relay modules which are installed in a set of protection panels. Bus bar protection schemes require significant signalling to and from each of the transmission circuits connected to the bus bar. This requires a large number of multi-core cables that connect the bus bar protection schemes to other relays and primary plant. Replacing a bus bar protection scheme, in the event of a permanent fault, will therefore take an extended period time to design, configure, install, test and commission. This would have a significant impact on the transmission network and potentially the national electricity market.

### 3.4 RISK EVALUATION

Transend has developed a comprehensive methodology for determining the criticality of transmission circuits. The 110 kV and 220 kV bus bars at Farrell Substation are categorised as criticality ‘5’ (with 5 being the highest criticality) primarily because of their importance to the transmission network in sustaining a reliable and secure electricity supply to customers.

A detailed probability weighted risk assessment of the impact of an outage of the 110 kV and 220 kV bus bar protection schemes at Farrell Substation has also been undertaken for a 15 year period. The risk assessment takes into account the projected reliability of the existing bus bar protection schemes and the expected unserved energy and the impact of loss of generation capacity and energy. Refer to attachment 4 for details of the analysis. The outcome of the analysis is presented in economic terms and has been used in the net present value analysis (NPV).

### 3.5 CAPITAL/OPERATING EXPENDITURE TRADE-OFFS

Replacement of the EHV Bus bar protection relays with relays that have self monitoring capabilities will reduce the frequency of preventive maintenance and hence operating expenditure. Transend estimates that the implementation of this project will result in savings of operating expenditure of up to $44 800 ($2009) over the forthcoming regulatory control period. These operating expenditure savings have already been included in the optimised works program. Although difficult to quantify, Transend also expects to realise a marginal reduction in corrective maintenance costs.

## 4. COMPLIANCE

As a requirement for entry into the National Electricity Market (NEM), Transend was required to undertake a compliance audit of its 220 kV and 110 kV bus bar protection schemes. The compliance audit identified that the 220 kV bus bar protection scheme does not meet the redundancy requirements specified in clause 5.1.9(d) of the National Electricity Rules (NER). In addition, it was identified that during an outage of the 220 kV bus bar protection scheme the back-up protection would not clear a bus bar fault in sufficient time to prevent system instability. As an interim measure, the back-up protection scheme settings were reduced. Whilst the reduced fault clearance times produce satisfactory stability analysis results for the present transmission network configuration, this arrangement is not satisfactory as a permanent solution since they may not provide appropriate discrimination.

The 110 kV bus bar protection scheme at Farrell Substation was found to be generally compliant. However it does not meet the redundancy requirements specified in clause 5.1.9(d) of the NER.

The replacement and duplication of the 110 kV and 220 kV bus bar protection schemes at Farrell Substation will ensure that Transend complies with the requirements of the NER as identified in Table 2.

**Table 2 – Compliance obligations, issues and project objectives**

| Reference | Compliance obligation | Substation issue | Project objective |
|---|---|---|---|
| NER Schedule 5.1.9(d) | 'If the fault clearance time determined under clause S5.1.9(e) of a primary protection system for a two phase to ground short circuit fault is less than 10 seconds, the primary protection system must have sufficient redundancy to ensure that it can clear short circuit faults of any fault type within the relevant fault clearance time with any single protection element (including any communications facility upon which the protection system depends) out of service.' | Stability studies in the protection audit report have demonstrated that the 220 kV bus bar protection requires duplicated high speed protection schemes to prevent system stability issues if the bus bar protection scheme is out of service. Conventional back-up is too slow to prevent system instability | Ensure reliable duplicate protection for 220 kV bus bar protection schemes |
| NER Schedule 5.1.9(k) | 'A primary *protection system* may clear faults other than *short circuit faults* slower than the relevant *fault clearance time*, provided that such faults would be cleared sufficiently promptly to not adversely impact on *power system security* compared with its operation for the corresponding *short circuit fault. ….*' | | |
| NER S5.1.2.1(d) | 'The *Network Service Provider* must ensure that all *protection systems* for lines at a *voltage* above 66 kV, including associated intertripping, are well maintained so as to be available at all times other than for short periods (not greater than eight hours) while the maintenance of a *protection system* is being carried out.' | Should either of the 220 kV or 110 kV bus bar protection schemes fail, it is highly unlikely that the scheme would be restored within the time required to comply with this obligation | Replace the 220 kV and 110 kV bus bar with new, protection schemes that have adequate redundancy |
| NER<br><br>S5.1a.8 (d). | The fault clearance time of a breaker fail protection system or similar back-up protection system for a short circuit fault of any fault type should not exceed the relevant time in column 4 of Table S5.1a.2 for the nominal voltage that applies at the fault location.<br><br>NB. Column 4 of Table S5.1a.2 states that the allowable maximum fault clearance time of 430 mS for a nominal voltage of more than 100kV but less than 250kV | If either the 220 kV or 110 kV bus bar protection schemes are out of service then the existing back-up protection clearance time is greater than the allowable clearance time stated in Table S5.1a.2.<br><br>This can result in NEMMCO denying Transend outages required to perform work | Provision of duplicated 220 kV and 110 kV bus bar protection will result in appropriate back-up protection fault clearance times. This will facilitate the performance of capital and maintenance work |
| NEMMCO Operating Procedure SO_OP6100 S8.1.3.1 | "Unless agreed to the contrary, after sixteen hours from the unplanned outage of one protection of a duplicated scheme the power system equipment must be switched out of service unless the protection scheme has been repaired or temporary protection installed." | Maximum allowable period for an unplanned outage of one protection of a duplicated scheme is 16 hours. The existing protection schemes are unreliable and are likely to fail. | Provision of duplicated 220kV and 110 kV bus bar protection will minimise risk of any future unplanned outage being greater than 16 hours |

# 5. CUSTOMER CONSULTATION

Transend has liaised with all relevant stakeholders regarding the planned works at Farrell Substation. Short outages will be required for each of the transmission line, transformer, and bus coupler circuits to implement the works. Some of these outages will constrain generation, so it is important that planned outages be coordinated with Hydro Tasmania to ensure that the impact of the planned outages is minimised.

# 6. BENEFITS

Replacement of the 220 kV and 110 kV bus bar protection schemes at Farrell Substation will provide the following benefits:

- the likelihood of unplanned bus bar protection scheme outages will be reduced, thereby improving the reliability and security of the transmission network;
- the occurrence of events that cause power flows through the substation to be constrained will be reduced;
- obsolete, unreliable and difficult to maintain protection schemes will be replaced with modern, reliable equipment that incorporate self supervision functions, thereby reducing ongoing operations and maintenance costs; and
- ensure ongoing compliance with the NER;
- facilitate future capital works at Farrell Substation;
- additional disturbance recording facilities will be provided, thereby improving power system analysis and fault response capability.
- reduction in the risk of non-operation of the bus bar protection scheme for bus bar faults. If faults are not cleared appropriately then bus bar faults can result in damage to primary equipment, system instability issues and forced outages; and
- reduction in the risk of mal-operation of the bus bar protection schemes due to partial failure of the scheme. Mal-operation of the scheme (ie operation of the scheme when there is no fault present) can result in forced outages and instability issues.

# 7. OPTIONS ANALYSIS

The following viable options have been considered to address the identified investment needs and compliance issues associated with the bus bar protection schemes at Farrell Substation:

1. maintain the existing bus bar protection schemes and defer replacement;
2. replace the 110 kV and 220 kV bus bar protection schemes at Farrell Substation without installing duplicate systems; and
3. replace the 110 kV and 220 kV bus bar protection schemes at Farrell Substation and install duplicate systems.

An alternative option that included maintaining the existing bus bar protection schemes and installing additional schemes was considered but discounted because it did not provide any material benefits. The existing bus bar protection schemes would still be susceptible to failure and would not be able to be repaired because spare components are not available.

The viable options are discussed in further detail in the following sections.

## 7.1- MAINTAIN THE EXISTING BUS BAR PROTECTION SCHEMES AND DEFER REPLACEMENTS

This option comprises maintaining the existing Brown Boveri type INX2 bus bar protection schemes.

This option would not satisfy the investment needs and compliance issues outlined in sections 3 and 4 of this paper. In addition, it would not align with the strategies detailed in the 'EHV Bus Bar Protection Asset Management Plan' (TNM-PL-809-0702) and would not be consistent with good electricity industry practice.

Maintaining the existing bus bar protection schemes presents the significant risk of failures impacting on the operation of the transmission network. The 110 kV and 220 kV bus zone protection schemes present an imminent risk that an extended failure will result in the significant constraint of power flow through the substation.

### 7.2- REPLACE THE BUS BAR PROTECTION SCHEMES WITH SINGLE SCHEMES AND DEFER PROVISION OF DUPLICATE SCHEMES

This option comprises the replacement of the 110 kV and 220 kV bus bar protection schemes with single schemes and then installing the duplicate schemes in 2016.

This option would address the performance issues associated with the bus bar protection schemes in the short term, but it would not provide any benefits when the new bus bar protection schemes are out of service because generation will still be constrained. In addition, the non-compliance issues identified in section 4 of this paper would continue to remain largely unresolved. Although the new bus bar protection schemes will be more reliable and require less maintenance than the existing schemes, outages will still be required while maintenance or modifications to the schemes are being undertaken, until the duplicated schemes were installed in 2016.

### 7.3- REPLACE THE BUS BAR PROTECTION SCHEMES WITH DUPLICATE SCHEMES

This option comprises the replacement of the 110 kV and 220 kV bus bar protection schemes with new, duplicated protection schemes.

This option would satisfy all of the investment needs and compliance issues outlined in sections 3 and 4 of this paper and would provide all of the benefits identified in section 6. In particular, the installation of duplicate bus bar protection schemes will ensure that Farrell Substation 110 kV and 220 kV continues to meet the requirements of the NER during outages of either bus bar protection scheme. The duplication of bus bar protection also enables the planned and unplanned maintenance to be conducted on one of the schemes without the need to rely on back-up distance protection schemes. As detailed in section 3 of this paper distance protection can not be guaranteed to respond to bus bar faults, and when they do it will be in a delayed clearance, potentially to the detriment of power system security.

Bus bar protection scheme outages will required when primary or secondary systems associated with a substation bay are upgraded or replaced. The replacement of a number of transmission line and transformer protection schemes at Farrell Substation is planned over the next five years. The installation of duplicate bus bar protection schemes will enable these works to proceed whilst maintaining one of the A or B schemes in service at all times.

In addition, this option is consistent with the strategies detailed in the 'EHV Bus Bar Protection Asset Management Plan' (TNM-PL-809-0702) and is consistent with good electricity industry practice.

## 8. OPTION ESTIMATES

A detailed net present value (NPV) analysis has been undertaken for each of the options considered. The NPV analysis takes into account initial and future capital expenditure, ongoing operations and maintenance costs, unserved energy costs and estimated costs associated with the loss of generation capacity. A summary of the NPV cost analysis for the options considered is presented in Table 3.

**Table 3 - Summary of NPV cost analysis**

| Option | | Net present value of costs ($M June 2007) |
|---|---|---|
| 1 | Maintain the existing assets and defer replacement | 2.45 |
| 2 | Replacement of assets but defer duplication of protection schemes | 2.92 |
| 3 | Replacement of assets and duplicate | 2.25 |

# 9. PREFERRED OPTION

Option three is the preferred option because it addresses all of the identified investment drivers and performance issues at the lowest NPV cost.

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | SHEFFIELD–FARRELL 220 KV TRANSMISSION LINES: PROTECTION SCHEME REPLACEMENTS |
| **TRIM REFERENCE** | D09/3550 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 2.0 |
| **TRANSEND CONTACT** | MARTIN O'BRYAN |
| **PROJECT NUMBER** | ND0914 |

## ATTACHMENT B2

# CONTENTS

# 1 BACKGROUND

The Sheffield–Farrell 220 kV transmission line protection schemes were commissioned in 1983 as part of the original Farrell Substation development.

Farrell Substation was established in 1982 to provide a connection point for the Pieman River power development and is a critical node in the Tasmanian transmission network. It connects up to 618 MW of generation to the Tasmanian power system and, in turn, the national electricity grid via Basslink. Under certain generation scenarios, Farrell Substation can transmit up to one third of Tasmania's generation requirement.

Sheffield Substation 220 kV is a critical node in the Tasmanian power system because it provides transmission connections to Hydro Tasmania's power stations located on the west coast of Tasmania and the Mersey Forth power scheme. It also supplies Aurora Energy's customers located in the north and north-west regions of Tasmania and has the capacity to transfer an additional 660 MW of power to the rest of the power system. During winter months, the amount of power supplied through Sheffield Substation can exceed 50 per cent of the overall power supplied via the transmission system.

The Sheffield–Farrell Nos. 1 and 2 220 kV transmission lines provide the sole 220 kV connection between the west coast of Tasmania and the remainder of the transmission network. These transmission lines are critical to the transmission network and are frequently operated beyond their firm capacity. The protection schemes on each of the Sheffield–Farrell Nos. 1 and 2 220 kV transmission lines comprise of static protection relays that are required to be replaced since they are a reliability and power system security risk. Additionally, their obsolete technology does not provide functionality that can be provided by modern protection schemes. Over the past 10 years Transend has installed modern microprocessor based devices on almost all of the backbone 220 kV transmission lines throughout the state. The Sheffield–Farrell No. 1 and 2 transmission lines are two of only three remaining lines (out of thirty two system wide) still protected by static technology relays.

# 2 PROJECT OVERVIEW

The Sheffield–Farrell 220 kV transmission line protection replacement project comprises the replacement of the:

- Sheffield–Farrell 220 kV No. 1 transmission line protection schemes at Sheffield and Farrell Substations; and
- Sheffield–Farrell 220 kV No. 2 transmission line protection schemes at Sheffield and Farrell Substations.

# 3 PROJECT TIMING

The Sheffield–Farrell 220 kV Transmission Line Protection Replacement project has been programmed to commence in 2009, with final commissioning in 2011.

This project is a key part of the Farrell Substation secondary systems replacement project.

# 4 INVESTMENT NEED

## 4.1 RELIABILITY AND SECURITY

The protection schemes on each of the Sheffield–Farrell Nos. 1 and 2 220 kV transmission lines at Farrell and Sheffield substations comprise one Reyrolle type THR distance protection relay (Main A scheme) and a Mitsubishi type MPC-SB static phase comparison protection relay (Main B scheme).

Transend has 22 Reyrolle type THR distance protection relays in service, of which four have failed over the past four years. The Reyrolle type THR relays suffer internal faults which have resulted in the relay being incorrectly blocked from operating or the relay failing to detect fault conditions. Both these failure modes would result in the relay not being able to clear an electrical fault from the network which is likely to result in the alternate protection scheme being solely responsible for clearing a fault on the power system. Therefore, the transmission line would no longer be protected by duplicate schemes.

In addition, it also is possible that internal relay faults may result in one or more of the scenarios described below:

- slow clearance of faults causing system stability problems or damage to primary electrical equipment;
- loss of capability to provide single pole auto-reclosing; and/or

- loss of back-up protection functionality.

Transend has not recorded any failures of the Mitsubishi MPC-SB protection relays over the last four years (out of the total of six devices presently in service in the transmission network) but Transend is aware that an identical relay in the Tasmanian Power System failed due to an internal fault during March 2008.

The failure rates for this type of protection technology have increased over the last few years and further failure rate increases are expected as the condition of the components continue to deteriorate. The components of these devices fail randomly and cannot be accurately predicted.

In addition both the Reyrolle type THR and Mitsubishi MPC relays types suffer the following asset management issues:

- they are no longer either manufactured or supported by the manufacturer;
- spares are no longer available from the manufacturer;
- spares held by Transend are aged and are likely to be prone to the same failures as the in-service assets; and
- the relays do not have ancillary or monitoring functionality.

**Table 1 - Transmission line protection scheme failures involving THR and MPC protection relays over the last 4 years**

| Station | Type | Device | Outage duration of Protection scheme (estimated average) | Description of Failure |
|---|---|---|---|---|
| Ulverstone | THR | A121B | 8 hours | Relay incorrectly indicating VT failure, requires VT detection card replacement. |
| Ulverstone | THR | A121B | 8 hours | Relay has VT Fail alarm. Cause is found to be a faulty backplane. Relay replaced. |
| Farrell | THR | T121B | 8 hours | VTS card failed, incorrectly indicating VT fail. Card replaced |
| Farrell | THR | D121 | 4 hours | During testing, relay failed to operate for zone 2 R-W phase fault. Card replaced. |

Refer to the EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) for further details regarding management of these types of schemes.

## 4.2 ASSET MAINTAINABILITY

The recent failures of these protection devices have challenged Transend’s capabilities of performing corrective maintenance on this technology of relays. At the present time a small number of experienced protection technicians are familiar with testing and potentially repairing these relays. An adequate number of spares are held for these devices and in most cases, faults have been resolved using spare cards within the 16 hour period allowed for unplanned maintenance as stated in the ‘NEMMCO Protection Systems Outage procedure’. However, these spares have all been recovered from de-commissioned assets and are thus prone to the same failures as the in-service equipment. Spare parts for this type of equipment are no longer available from the manufacturer.

The THR and MPC relays age, technology and lack of self supervision dictate that routine maintenance be performed twice as often (every three years) than modern devices. Field staff have also noted that the devices are more likely to fail under routine testing conditions, so accelerating the routine testing interval is likely to create more relay faults. This circumstance also brings into question the ongoing reliability of this technology, that is, the relays although seemingly healthy, may fail when called on to operate.

## 4.3 RISK EVALUATION

Transend has developed a comprehensive methodology for determining the criticality of transmission circuits[1]. Both 220 kV Transmission Line circuits at Farrell Substation are categorised as criticality '5' (with 5 being the highest criticality) primarily because of their importance to the transmission network in sustaining a reliable and secure electricity supply to customers.

## 4.4 CAPITAL/OPERATING EXPENDITURE TRADE-OFFS

Replacement of the 220 kV Transmission Line protection schemes with modern relays will reduce the frequency of preventive and corrective maintenance and hence operating expenditure.

Transend estimates that the implementation of this project will result in savings of operating expenditure of up to $176,472 (in $2009) over the forthcoming regulatory control period.

These savings have been incorporated into the economic analysis (document D09/2677).

## 4.5 COMPLIANCE

As a requirement for entry into the National Electricity Market (NEM), Transend was required to undertake a compliance audit of its 220 kV transmission line protection schemes. The compliance audit[2] identified that the Sheffield–Farrell 220 kV Transmission line protection schemes are compliant with the NEC. The circuits were compliant to clauses S5.1a.8(b to e), S5.1.9(d) and S5.1.9(f) of the NER.

As described in Section 3.2, Transend field staff report that the THR relays have a consistent history of failing under routine testing conditions. These occurrences threaten Transend's compliance obligation to ensure planned maintenance is performed in a period not greater than eight hours (NER S5.1.2.1(d) – refer to Table 2 below). It is increasingly likely that the degrading condition of these schemes will result in Transend's non-conformance with this obligation which would result in the affected transmission line being forcibly removed from service by NEMMCO until the protection scheme is repaired.

It is also highly likely that the increasingly unreliability of these protection schemes will result in the schemes failing in a manner that will result in the equipment requiring emergency replacement. When this event occurs Transend will not be able to ensure compliance with NEMMCO Operating Procedure SO_OP6100 S8.1.3.1. This procedure states that without special agreement, if an unplanned outage of one protection of a duplicated scheme is longer than sixteen hours, then the power system equipment must be switched out of service unless the protection scheme has been repaired or temporary protection installed.

The replacement of the 220 kV transmission line protection schemes will ensure that Transend complies with the requirements of the NER and NEMMCO Operating Procedures as identified in Table 2. The protection schemes will also continue to comply with the other clauses of the NER (ie S5.1a.8 and S5.1.9) that the existing schemes comply with.

**Table 2 – Compliance obligations, issues and project objectives**

| Reference | Compliance obligation | Substation issue | Project objective |
|---|---|---|---|
| NER S5.1.2.1(d) | 'The *Network Service Provider* must ensure that all *protection systems* for lines at a *voltage* above 66 kV, including associated inter-tripping, are well maintained so as to be available at all times other than for short periods (not greater than eight hours) while the maintenance of a *protection system* is being carried out.' | Should either of the 220 kV transmission line protection schemes fail, it is possible that the scheme would not be restored within the time required to comply with this obligation | Replace the 220 kV transmission line protection schemes with new, protection schemes that are unlikely to fail during routine testing. |

[1] Transend Networks Pty Ltd, Asset Criticality Assignment Standard, TNM-GS-809-0915

[2] Power Systems Consultants, Transend Audit Assessment of Compliance with the National Electricity Code, March 2005.

| Reference | Compliance obligation | Substation issue | Project objective |
|---|---|---|---|
| NEMMCO Operating Procedure SO_OP6100 S8.1.3.1 | 'Unless agreed to the contrary, after sixteen hours from the unplanned outage of one protection of a duplicated scheme the power system equipment must be switched out of service unless the protection scheme has been repaired or temporary protection installed.' | Maximum allowable period for an unplanned outage of one protection of a duplicated scheme is 16 hours. The existing protection schemes are unreliable and are likely to fail. | Provision of an upgraded 220 kV transmission line protection schemes will minimise risk of any future unplanned outage being greater than 16 hours. |

# 5 CUSTOMER CONSULTATION

Transend will liaise with all relevant stakeholders regarding the planned works at Farrell and Sheffield substations. Outages will be required for each of the transmission lines to implement the works. Some of these outages will constrain generation, so it is important that planned outages be well coordinated to ensure that the impact of the planned outages is minimised.

# 6 BENEFITS

Replacement of the 220 kV transmission line protection schemes at Sheffield and Farrell substations will provide the following benefits:

- the likelihood of unplanned transmission line protection scheme outages will be reduced, thereby improving the reliability and security of the transmission network;
- the occurrence of events that cause power flows through Farrell Substation to be constrained will be reduced;
- obsolete, unreliable and difficult to maintain protection schemes will be replaced with modern, reliable equipment that incorporate self supervision functions, thereby reducing ongoing operations and maintenance costs;
- ensure ongoing compliance with the NER;
- additional disturbance recording and distance to fault facilities will be provided, thereby improving power system analysis and fault response capability;
- allow full compliance with Transend's internal design standard for the protection of EHV transmission lines;
- reduction in the risk of non-operation of the transmission line protection schemes. If faults are not cleared appropriately then faults can result in damage to primary equipment, system instability issues and forced outages; and
- reduction in the risk of mal-operation of the transmission line protection schemes due to partial failure of the scheme. Mal-operation of the scheme (ie operation of the scheme when there is no fault present) can result in forced outages and system instability issues.

# 7 OPTIONS ANALYSIS

The following viable options have been considered to address the identified investment needs and compliance issues associated with the Sheffield–Farrell 220 kV transmission line protection schemes:

- maintain the existing transmission line protection schemes and defer replacement; and
- replace transmission line protection schemes.

An alternative option that included replacing the Main A protection scheme (THR relay) and deferring the replacement of the Main B protection scheme (MPC relay) additional schemes was considered but discounted because this option would not provide any material benefits since the existing protection schemes would still be susceptible to failure. It would also create a technological mismatch between the relays protecting a particular transmission line.

The viable options are discussed in further detail in the following sections.

### 7.1 OPTION 1: MAINTAIN EXISTING TRANSMISSION LINE PROTECTION SCHEMES AND DEFER REPLACEMENTS

This option comprises maintaining the existing transmission line protection schemes.

This option would not satisfy the investment needs and compliance issues outlined in Sections 3 and 4 of this paper. In addition, it would not align with the strategies detailed in the EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) and would not be consistent with good electricity industry practice.

Maintaining the existing transmission line protection schemes presents the significant risk of failures impacting on the operation of the transmission network.

### 7.2 OPTION 2: REPLACE TRANSMISSION LINE PROTECTION SCHEMES

This option comprises the replacement of the 220 kV transmission line protection schemes with new protection schemes.

This option would satisfy all of the investment needs and compliance issues outlined in section 4 of this paper and would provide all of the benefits identified in Section 6.

In addition, this option is consistent with the strategies detailed in the EHV Transmission Line Protection Asset Management plan (TNM-PL-809-0701) and is consistent with good electricity industry practice.

## 8 OPTION ESTIMATES

A detailed net present value (NPV) analysis has been undertaken for each of the options considered. The NPV analysis takes into account initial and future capital expenditure, ongoing operations and maintenance costs, unserved energy costs and estimated costs associated with the loss of generation capacity. A summary of the NPV cost analysis for the options considered is presented in Table 3.

**Table 3 – Summary of NPV cost analysis**

| Option | | Net present value of costs ($M June 2007) |
|---|---|---|
| 1 | Maintain the existing assets and defer replacement | 2.36 |
| 2 | Replacement of assets | 1.83 |

## 9 PREFERRED OPTION

Option two is the preferred option because it addresses all of the identified investment drivers and performance issues at the lowest NPV cost.

The estimated capital cost of this option is $2 million ($Dec 2008).

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | NEW NORFOLK SUBSTATION 110 KV PROTECTION REPLACEMENTS |
| **TRIM NUMBER** | D09/3706 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 2.0 |
| **TRANSEND CONTACT** | TREVOR SCOTT |
| **PROJECT NUMBER** | ND0961 |

## ATTACHMENT B3

# CONTENTS

# 1 BACKGROUND

New Norfolk Substation was commissioned in 1987. The substation is a critical part of the transmission network in southern Tasmania because it provides key connections to generation sources located in the Upper Derwent area of Tasmania. It supplies Boyer paper mill and Aurora Energy's customers via two 110/22 kV transformers. It also provides 110 kV connections to Chapel Street, Creek Road and Meadowbank substations and Tarraleah Switching Station. The substation also has one 30 MVAr 110 kV capacitor bank installed. A power circuit one line diagram for New Norfolk Substation is provided as Attachment 3.

The secondary assets that will be replaced in this project will be 27 years old when decommissioned and will have exceeded their assigned class life of 15 years as defined by Sinclair Knight Merz in its 'Assessment of Economic Lives for Transend Regulatory Asset Classes' report prepared in April 2008.

# 2 PROJECT OVERVIEW

The New Norfolk Substation 110 kV Protection Replacements project replaces obsolete, unreliable and difficult to maintain protection and control devices that are in service at New Norfolk Substation. The majority of the protection and control devices at New Norfolk Substation are of the static type. Across the transmission network, static devices, including those in service at New Norfolk Substation are starting to fail regularly, typically requiring card replacements to maintain good working order.

Spare parts are no longer available from manufacturers for static devices of the types in service at New Norfolk Substation; hence it is important that a prioritised replacement program be established to enable spares to be made available from the de-commissioned units. By replacing all of the static relays at New Norfolk Substation, Transend will be able to support the remaining in-service schemes at other substations until their scheduled replacement. Spares holdings for a certain devices at New Norfolk Substation are at critically low levels.

The project includes the replacement of the following protection schemes at New Norfolk Substation:

- 110 kV bus bar protection scheme;
- Meadowbank–New Norfolk 110 kV transmission line protection scheme;
- New Norfolk–Creek Road 110 kV transmission line protection scheme;
- New Norfolk–Chapel Street 110 kV transmission line protection scheme; and
- Tarraleah–New Norfolk 110 kV transmission line protection scheme.

# 3 INVESTMENT TIMING

The New Norfolk Substation 110 kV Protection Replacement project has been programmed to be completed in 2014.

Where practicable, planned outages will be coordinated with other planned works, particularly planned protection scheme replacements at the remote ends of the connecting transmission lines.

# 4 INVESTMENT NEED

This project is required to achieve the following capital expenditure objectives identified in clause 6A.6.7(a) of the National Electricity Rules (Rules):

- maintain the quality, reliability and security of supply of prescribed transmission services; and
- maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

The key investment driver for this project is to address identified issues presented by the primary and secondary assets at New Norfolk Substation. The key issues relating to each major asset category are discussed in further detail in this section.

## 4.1 110 KV BUS BAR PROTECTION

The 110 kV bus bar protection at New Norfolk Substation is a Toshiba type TBB7B static scheme that was installed in 1987. The TBB7B protection scheme was the only one of this type installed in the transmission network. The TBB7B protection scheme is no longer support by the manufacturer and Transend has only limited spares in stock.

The TBB7B protection scheme is a high impedance scheme. It therefore requires current transformer secondary circuits to be switched through disconnector auxiliary switches. Transend has standardised on the application of low impedance bus bar protection schemes at substations that have double bus bar arrangements (eg New Norfolk Substation) to avoid potential substation outages due to disconnector auxiliary switch failures. Routine testing of bus bar protection schemes are both expensive and are susceptible to unplanned operations due to finger faults during testing. Replacement of the existing bus bar protection scheme with a modern low impedance scheme will allow routine testing intervals to be increased from three to six years and will significantly reduce the risks associated with finger faults during routine testing.

The EHV Bus Bar Protection Asset Management Plan (TNM-PL-809-0702) recommends that obsolete bus bar protection schemes like that in service at New Norfolk Substation be replaced with microprocessor based schemes.

## 4.2 TRANSMISSION LINE PROTECTION

The distance protection relays at New Norfolk Substation on the Chapel Street, Creek Road, Meadowbank and Tarraleah 110 kV transmission lines are Brown Boveri type LZ92 and ASEA type RAZOA static devices, that were installed in 1987. There are 13 LZ92 and 9 RAZOA relays in-service on Transend's network. There are limited spares for each device type and both are no longer supported by the manufacturer.

Substation redevelopment works planned at Creek Road and Meadowbank Substation and Tarraleah Switching Station provides an opportunity to cost-effectively replace the transmission line protection schemes at New Norfolk Substation.

Transend has standardised on the installation of duplicated current differential schemes on its transmission lines where practicable. Current differential protection has a distinct advantage over distance protection because it is immune to under or over reaching as a result of varying zero sequence mutual impedances. By replacing the transmission line protection at New Norfolk Substation at the same time as the remote ends, Transend will improve protection co-ordination and improve transmission network performance. If the replacement of protection systems at either end of transmission line is undertaken years apart there is a significant likelihood that compatible current differential relays will not be available. Given the fast rate of change in relay technology, it is prudent to replace protection systems at both ends of transmission line at the same time.

## 4.3 COMPLIANCE

The Meadowbank–New Norfolk 110 kV transmission line protection scheme does not meet the fault clearance times specified in the Rules for a three-phase fault due to there being no accelerated schemes installed. The impact of this non compliance is the possible loss of synchronism at Meadowbank Power Station for a transmission network fault. Replacement of the protection schemes on this transmission line provides the opportunity to cost-effectively address this non-compliance.

## 4.4 MAINTENANCE COSTS

The majority of the existing relays at New Norfolk Substation are of the static type which requires testing at three yearly intervals. The proposed microprocessor type relays have self-diagnostic features and require testing at six yearly intervals. This will result in operational cost savings and a reduction in the risk of inadvertent transmission network outages during the intrusive testing of the protection systems.

The new microprocessor based protection schemes will provide in-built disturbance recording features that enable easy post-fault diagnosis and faster outage restoration. These features will reduce ongoing operational costs associated with fault investigations. The installation of remote interrogation facilities will also reduce operational expense of uploading these disturbance records.

### 4.5 GOOD INDUSTRY PRACTICE

In recent years, most of utilities in Australia have been systematically replacing protection and control systems of an obsolete design with new digital devices. Past experience has shown that protection and control upgrades have significantly enhanced transmission network reliability and plant availability.

It is expected this trend will continue for the next few years until all legacy secondary systems are replaced with modern technology.

## 5 CUSTOMER CONSULTATION

Transend will liaise directly with relevant stakeholders regarding the intent, scope and implementation of the project.

## 6 BENEFITS

The successful implementation of the New Norfolk Substation 110 kV Protection Replacements project will provide the following benefits:

- it will contribute towards the achievement of the capital expenditure objectives;
- the risk of unplanned outages due to secondary system failures will be reduced, thereby improving the reliability of the transmission network;
- the occurrence of events that cause power flows through the substation to be constrained will be reduced;
- the new protection systems will ensure compliance with the Rules;
- obsolete, unreliable and maintenance intensive protection and control devices will be replaced with modern, reliable equipment that incorporate self supervision functions, thereby reducing ongoing operations and maintenance costs;
- spares will be made available for secondary assets at other substations;
- additional disturbance recording and fault location equipment will be provided, thereby improving power system analysis and fault response capability; and
- the new secondary systems will adequately cater for planned future works with minimal re-work.

## 7 OPTIONS ANALYSIS

The following viable options have been considered for the New Norfolk Substation 110 kV Protection Replacement project:

1. maintain the existing assets and defer replacement; and
2. undertake the identified works as an integrated project.

The option to undertake the identified works on an individual project basis was considered but was discounted because it is clearly not a cost-effective approach.

These options are discussed in further detail in the following sections.

### 7.1 MAINTAIN THE EXISTING ASSETS AND DEFER REPLACEMENT

This option essentially comprises maintaining the existing secondary systems and to undertake repairs as necessary.

This option does not address the compliance, operational, reliability and maintenance issues outlined in this paper. In addition, it does not align with good electricity industry practice or the strategies detailed in the respective asset management plans. Maintaining the existing secondary systems presents the significant risk of failures impacting on the operation of the transmission network. It also would not provide adequate spares to sustain the serviceability of the protection schemes into the future.

This option is also not efficient because it would not take advantage of the benefits associated with coordinating the protection scheme replacements with those at the connecting substations and switching station.

Deferral of this project would result in the need for additional operating expenditure of up to $70,000 over the next seven years to carry out planned maintenance. This figure does not include any costs associated with corrective maintenance or the impact of unplanned outages.

### 7.2 UNDERTAKE THE IDENTIFIED WORKS AS AN INTEGRATED PROJECT

This option proposes that all of the identified works associated with the secondary systems at New Norfolk Substation be integrated into a single project. This approach will ensure that the works are undertaken under a single contract, hence reducing contract management costs and avoiding potential hazards associated with critical design information handover between different contractors. The cost of mobilisation and de-mobilisation will be reduced. Delivering this project in a shorter time span will also limit exposure to changing technology.

## 8 OPTION ESTIMATES

A comparison of the net present value of options is provided in Table 1.

**Table 1 – Comparison of options considered**

| Option | | Net present value of costs ($M June 2007) |
|---|---|---|
| 1 | Maintain the existing assets and defer replacement | 5.27 |
| 2 | Undertake the identified works as an integrated project | 3.97 |

The capital project estimate is $5.58 million ($2008–09).

## 9 PREFERRED OPTION

Option 2 is the preferred option because it is the least-cost solution that addresses all of the identified issues.

# INVESTMENT EVALUATION SUMMARY

| | |
|---|---|
| **TITLE** | BURNIE-WARATAH 110KV TRANSMISSION LINE WOOD POLE REPLACEMENT |
| **TRIM REFERENCE** | D09/4192 |
| **DATE** | JANUARY 2009 |
| **REVISION STATUS** | 1.3 |
| **TRANSEND CONTACT** | PETER JOHNSON |
| **JOB/PROJECT NUMBER** | ND0966 / BC 4910 / 3296 |

## ATTACHMENT C1

# CONTENTS

# 1 BACKGROUND

This wood H pole line was built in 1966 and commissioned in 1967 and comprises of 222 structures. The poles are nearing the end of their useful life, normally expected to be around 45 years. Nineteen structures were replaced when the Hampshire Substation was installed in 1994.Twelve structures were replaced in 2006 as a result of the poles being condemned.

# 2 PROJECT OVERVIEW

This project involves replacing existing wood poles and crossarms on the 110kV Burnie - Waratah transmission line with "Sureline" steel poles and new crossarms.

The number of structures requiring replacement will vary and is dependent on the ongoing 3 year pole inspection program. The next pole inspection is planned for 2007 – 2008. Forecast replacements are based on replacement rates advised by Aurora Energy.

The asset management strategy adopted here is outlined in the Transmission Line Support Structure Asset Management Plan TNM-SY-808-0223. The strategy is to replace the twin wood pole structure with a new cost effective product, a single parallel tube "Sureline" steel pole from BlueScope Steel.

# 3. INVESTMENT TIMING

Expenditure in 2010/11 and 2013/14, aligned with the 3 year inspection program.

# 4. INVESTMENT NEED

Once poles have been condemned Transend must replace these within 3 months to ensure appropriate pole strength safety factors. If the poles are not replaced they would have to be removed altogether, making the transmission line inoperable and reducing security of supply.

# 5. CUSTOMER CONSULTATION

Land owners are to be contacted prior to entry onto property.

# 6. BENEFITS

Undertaking the wood pole replacement program will provide the following benefits:

- continue to sustain a reliable supply by replacing condemned poles in a timely manner;
- reduced capital cost for use of steel structures relative to wooden structures;
- reduced operating expenditure, with 3 yearly inspection of wood poles no longer required;
- increased resistance to fires caused by bushfires or pole top fire events; and
- environmental advantages associated with use of steel rather than wood poles.

## 7. OPTIONS ANALYSIS

The following viable options have been considered:

1. Replace existing wood poles in twin wood pole structures with new wood poles i.e. 2 wood poles required.
2. Replace existing twin wood pole structures with single steel pole at suspension towers and twin steel poles at strain towers.

The Burnie - Waratah Wooden Poles Transmission Line HV Insulator - Condition Assessment Report TNM-CR-808-0888 provides further information on these options.

## 8. OPTION ESTIMATES

Whole-of-life costing indicates that replacement with steel poles provides the least cost solution. Estimates have been prepared based on this basis.

## 9. PREFERRED OPTION

The preferred option is to replace existing wood pole structures with steel poles.

Historical inspection and test results indicate that approximately 70 structures will be condemned and require replacement in the next planning period at a total cost of approximately $5.8m dollars ($2008-09).

## 10. RISK EVALUATION

The replacement of the poles will undertaken with the transmission line out of service and pre qualified external service providers will be required to undertake the replacements. The contractor will install the poles to a standard design.

By having the transmission line out of service and using pre qualified service providers the risk rating is assessed as low.

# Burnie-Waratah 110 kV Transmission Line Wood Poles

# Condition Assessment Report

**APPROVED**

TRANSEND

### CONTACT

*This document is the responsibility of the Engineering and Asset Services Group, Transend Networks Pty Ltd, ABN 57 082 586 892.*

*Please contact Transend's Manager Engineering and Asset Services Group with any queries or suggestions.*

### REVIEW DATE

*This document is due for review not later than June 2009*

### RESPONSIBILITIES

#### Implementation

*All Transend staff and contractors.*

#### Audit

*Periodic audits to establish conformance with this document will be conducted by Transend's Asset Strategy & Planning Group.*

#### Compliance

*All Group Managers*

#### Document Management

*Asset Strategy & Planning Group*
*Engineering & Asset Services Group - Transmission Lines*

### MINIMUM REQUIREMENTS

*The requirements set out in Transend's documents are minimum requirements that must be complied with by Transend staff and contractors, including designers and other consultants. The user is expected to implement any practices which may not be stated but which can reasonably be regarded as good practices relevant to the objective of this document without non-compliance with the specific requirement of this document. Transend expects the users to improve upon these minimum requirements where possible and to integrate these improvements into their procedures and quality assurance plans.*

# CONTENTS



# LIST OF FIGURES

# EXECUTIVE SUMMARY

This document assesses the condition of Transend's population of wood poles currently installed on the Burnie–Waratah 110 kV transmission line.

The Burnie–Waratah 110 kV transmission line was commissioned in 1967 and was constructed as a single circuit 'H' pole line with each support structure comprising two treated hardwood poles and a steel crossarm. The transmission line currently has 422 treated wood poles (two per structure) and 14 steel poles (one per structure) installed at 223 locations. The wood poles have installation dates ranging from 1966 to 2001.

The wood poles are tested every three years, with the next test regime to commence during summer in 2010-11. These tests are undertaken by contractor Aurora Energy Pty Ltd (Aurora). Aurora is considered by Transend as the treated wood pole experts in Tasmania; in that it successfully manages a population of over 250 000 wood poles. Transend consequently utilise Aurora's proven pole testing methodology.

The treated wood pole failure rate for this transmission line when compared against the HEC/Aurora historical and estimated treated wood pole failure rate shows that the wood poles on this transmission line are failing at a faster rate (Trim Ref D08/68430). The earliest installed treated wood poles on this line are now 42 years old, and the estimated failure curve indicates that the last original treated wood pole on this transmission line will be replaced in 2033 (67 years old) as against 2039 (73 years old) from the HEC/Aurora data. The actual failure curve when forward estimated indicates that at least thirty poles, installed in 1966, are expected to require replacing in each future three yearly inspection cycle.

During the 1980s the wood poles were reinforced by attaching a separate shorter pole to the existing pole as a support. This approach was found to be ineffective in providing sufficient support when it was identified that the internal weakening of the original pole was not only at or below ground level but also extended well into the upper portion of the pole. The internal weakening was also not limited to rot, but included a fungal attack through cracks of the outer surface of the pole as it weathers and ages. As such, reinforcement of an existing weakened pole, either by a separate supporting pole or metal stakes at ground level, is no longer recognised as a technically viable life extension option. Since the 1980s and until 2006, all condemned poles and the existing reinforced poles have been replaced with new treated wood poles.

In 2006, an evaluation was conducted into replacing the wood poles with steel poles, as and when they were condemned. The report considered replacing both wood poles in the structure with steel poles. The report found that there was a whole of life premium of 14 per cent in replacing two treated wood poles with two modern steel poles. Further analysis has identified that replacing two wood poles with a single steel pole (for suspension structures) and two steel poles (for strain structures) is approximately 16 per cent cheaper than the traditional method. This revised pole replacement methodology was adopted and is currently being utilised.

The future management strategy is to progressively replace the wood poles on this transmission line with steel poles, one at a suspension structure and two at a strain structure, as and when the wood poles are confirmed condemned through testing.

Historical inspection and test results indicate that approximately 70 structures will be condemned and require replacement in the next planning period at a total cost of approximately $4.6m dollars.

# 1 BACKGROUND

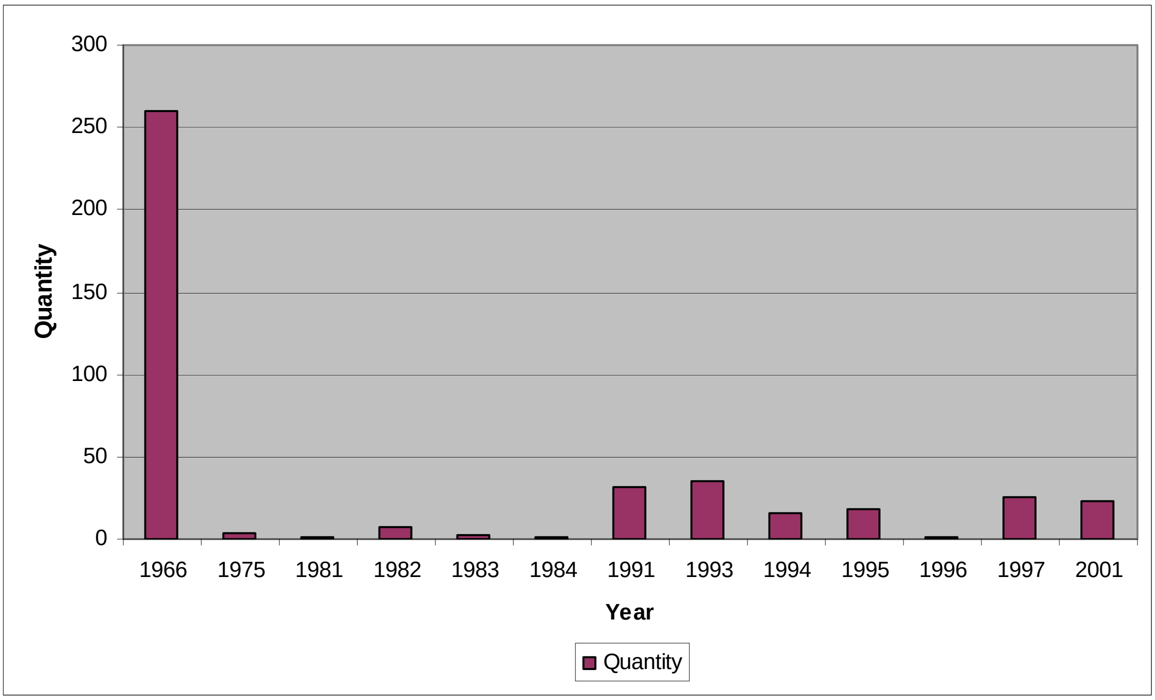
This document assesses the condition of Transend's population of wood poles currently installed on the Burnie–Waratah 110 kV transmission line.

The Burnie–Waratah 110 kV transmission line was commissioned in 1967 and was constructed as a single circuit 'H' pole line using two treated hardwood poles and a steel crossarm. The transmission line currently has 422 wood poles and 14 steel poles installed at 223 locations. The wood poles have installation dates ranging from 1966 to 2001. It is intended that this transmission line will remain a part of Transend's transmission network in its current form for the foreseeable future.

The average age of the wood poles on this transmission line is 31 years, with 58 per cent of the total structures now 42 years old. The wood pole age profile for this transmission line is presented in figure 1.

The low number of pole replacements between 1981 and 1984 reflect the preference for pole staking at that time.

**Figure 1 – Wood pole age profile as at September 2008**




# 2 ASSET ASSESSMENT

The assessment of the wood poles is based on the Aurora Energy Pole Inspection and Maintenance Procedure NP R AM 27-1 which details the standard method for inspection and maintenance treatment of wood poles.

The wood poles are tested every three years, with the next test due during summer in 2010-11. The tests are undertaken by Aurora utilising its own proven methodology. Inspectors are responsible for inspection of poles, pole top hardware and conductors for serviceability and defects, testing and treatment of poles against wood decay, and recording the details. On completion of the tests, Aurora provides a report to Transend on the condition of each pole on the transmission line.

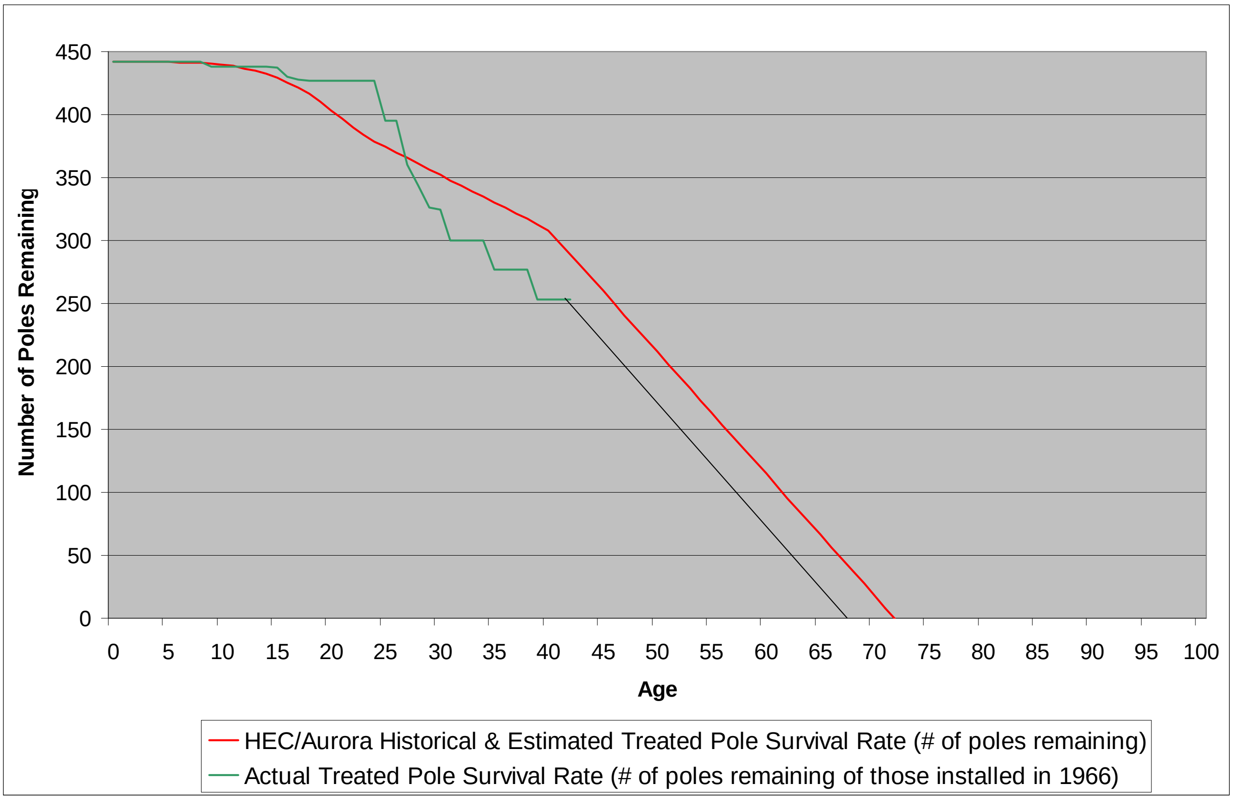
## 2.1 Reliability

Since the transmission line was commissioned in 1967, 41.5 per cent of the wood poles have been replaced as they have been assessed as no longer in a serviceable condition. There have been no physical wood pole failures caused by structure failure on this transmission line since commissioning.

Experience indicates that a small percentage of poles show marked deterioration in the first 15 to 20 years of service, due to ground water, soil conditions and flaws or holes creating a micro climate that promotes decay and deterioration of the wood pole. The rate of deterioration can be decreased by the application of decay control maintenance treatment, especially when applied to sound wood adjacent to the decayed part.

The pole failure curve for this transmission line, against the HEC/Aurora historical and estimated treated pole survival rate, shows that the poles on this transmission line are failing faster, in that after 42 years of service 41.5 per cent have been condemned versus the HEC/Aurora estimated failure rate of 35 per cent condemned (see figure 2).

**Figure 2 – Actual wood pole failure rate vs. HEC/Aurora historical and estimated failure rate**




The actual failure curve when forward estimated indicates that of those poles installed in 1966, at least ten poles are expected to require replacing annually from now on. As testing is conducted on a three year cycle, this equates to at least 30 poles expected to be condemned every three years. The forward estimated failure rate indicates that the last original treated wood pole on this transmission line will be replaced in 2033 (67 years old) as against 2039 (73 years old) from the HEC/Aurora data.

## 2.2 Physical Condition

The poles are considered to be in serviceable condition until the condition assessment determines that the wood pole no longer has the required pole strength safety factors, and is condemned. Further information on wood pole condition is presented in section 2.3 below.

## 2.3 MAINTENANCE

Preventive maintenance practices such as regular inspection programs and testing are used to identify deteriorated wood poles. When testing identifies sufficient deterioration in the wood pole condition these wood poles will be replaced as per the management strategy. This replacement must occur within three months of the inspection date.

The rate of wood pole deterioration depends on the species of timber, the initial preservative treatment, installation location, soil conditions, method of inspection, drilling, excavation and reinstatement. Decay occurs when both moisture and oxygen are present, typically in the location from ground level to approximately 300 mm below ground level.

Experience indicates that a small percentage of poles show marked deterioration in the first 15 to 20 years of service, due to ground water, soil conditions and flaws or holes creating a micro climate that promotes decay and deterioration of the wood pole. The rate of deterioration can be decreased by the application of decay control maintenance treatment, especially when applied to sound wood adjacent to the decayed part.

During the 1980s the wood poles were reinforced by attaching a separate shorter pole to the existing pole as a support. This was found to be ineffective in providing sufficient support when it was found that the internal deterioration of the original pole was not only at or below ground level but was also found to extend well up into the upper portions of the pole (see figure 3). The internal deterioration was found to include a fungal attack through cracks of the outer surface of the pole as it weathers and ages.

**Figure 3 – Treated wood pole with fungal degradation 9 metres above ground line.**


As such, reinforcement of an existing deteriorated pole, either by a separate supporting pole or metal stakes at ground level, is no longer recognised as a technically viable refurbishment option. Since this earlier period, and until 2006, all condemned poles and the existing reinforced poles have been replaced with new treated wood poles.

In 2006 an evaluation[1] was conducted into replacing the wood poles with steel poles, as and when they were condemned. The report looked at replacing both wood poles in the structure with steel poles. The report found that there was a whole of life premium of 14 per cent in replacing two treated wood poles with two modern steel poles. However, the benefits of steel structures in comparison to wood structures are numerous including:

(a) improved resistance to fire (both pole and pole top);

(b) unlike some wood poles, steel poles do not leach chemicals into the soil;

(c) greater availability; and

(d) significantly lighter than wood poles.

The only negative aspect of a steel pole is the potential for corrosion. However, through the utilisation of galvanised surfaces, top and bottom pole caps, and HDPE sleeve at the ground to air interface, the risk of corrosion is sufficiently mitigated, resulting in a life expectancy of approximately 75 years.

Due to these advantages, Transend investigated whether further cost savings could be obtained through the replacement of two wood poles with a single steel pole. It was found that this was technically feasible and the cost per suspension tower replacement was approximately 16 per cent cheaper than utilising two wood poles.

Based on this evaluation it was decided that a new structure using only one steel pole would be a viable alternative for suspension structures with the two steel pole replacements being adopted for the strain structures.

### 2.4 Spare parts and contingency planning

Transend has a small number of steel poles to cater for contingency events and can source wood poles from local suppliers in emergencies.

### 2.5 Safety

As detailed within Transend's Transmission Line Support Structures Asset Management Plan (TNM-SY-808-0223), the risk of some aged wood poles failing and causing the transmission line conductor to fall and either cause a fire or expose line workers or the public to a safety hazard is high. The risk mitigation actions recommended in this instance are to inspect, test and replace (where needed) affected structures.

### 2.6 Environment

Environmental risks include the possibility of a bushfire start and the inappropriate disposal of the Copper Chrome Arsenate (CCA)[2] impregnated wood poles.

## 3 ASSET MANAGEMENT OPTIONS

The costing comparisons associated with the following options are contained in the 2006 evaluation report (see footnote 2).

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[1] Hydro Tasmania Consulting report '110kV Burnie-Waratah transmission line comparative cost study of Sureline Steel poles as an alternative replacement for condemned wood poles' dated 7 June 2006.

[2] CCA is a mixture of inorganic components containing the elements copper, chromium and arsenic. Lebow (1996) explains that the primary role of chromium is in CCA fixation, through a complex series of reactions driven by its reduction from the hexavalent state to the trivalent state after it is applied to the wood. Copper and arsenic provide the efficacy of the preservative, copper primarily as a fungicide, and arsenic more for its activity as an insecticide, and also for activity against copper-tolerant fungi. Cookson (2001) claims that while arsenic was originally thought to be needed for insect control, the latest theory is that arsenic is more useful in controlling copper-tolerant brown rotting fungi.

**Option 1: Replace existing wood poles with new wood poles as and when they are condemned**

This option requires Transend to continue with the ongoing testing program at a cost of $36 000 every three years, and replace the wood poles with new wood poles as and when they are condemned. The number of poles requiring replacement will be the same as for Option 2, but will come at approximately 30 per cent higher cost. This option also fails to take advantage of the opportunity to introduce the benefits of steel poles (ie. increased fire resistance, greater availability, weight savings).

**Option 2: Replace existing wood poles with new steel poles as and when they are condemned**

This option requires Transend to continue with the current testing program at a cost of $36 000 every three years, and replace wood pole structures with either a single or double steel pole structure as and when the wood poles are condemned. This option will reduce and ultimately eliminate the current three yearly pole testing program thus providing a reduction in maintenance costs while simultaneously introducing all the benefits of a steel pole structure as outlined in 2.3.

Historical inspection and test results indicate that approximately 70 structures will be condemned and require replacement in the next planning period at a total cost of approximately $4.6m dollars.

**Preferred option:**

Option 2 is the preferred option.

# 4 FUTURE MANAGEMENT STRATEGY

The future management strategy is to replace the wood poles on this transmission line with steel poles, one at a suspension structure and two at a strain structure, as and when the wood poles are confirmed condemned through testing.